ANALYSIS OF SELECTED PROBLEMS RELATED TO TRANSPORTATION OF ILLINOIS COAL

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RELATED TO TRANSPORTATION OF ILLINOIS COAL

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Solid and Hazardous Waste	- White	Olive
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Noise Management	- Buff	Orange
Energy	- Cherry	Red
Information Services	- Canary	Yellow

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PREFACE

This study was undertaken as a result of the recommendations of an earlier study (IINR Document No. 81/10) concerning the proposed Illinois-Florida coal slurry pipeline and the emergence in late 1980 of export coal as a national policy issue. The report provides information and analysis that hopefully will lead to an objective, reasoned policy debate concerning how these two issues affect the State of Illinois.

The research team has benefited immensely from discussions with many persons in the transportation and energy industries. While it is not possible to acknowledge them individually, I would like to thank them for the generous contribution of their time, without which the study would not have been possible.

Likewise, we have benefited from comments and criticisms of earlier drafts of this report by Norman Wolf, Division of Water Resources, Illinois Department of Transportation and Dr. Subhash B. Bhagwat, Head, Mineral Economics Section, Illinois Geological Survey. We have also been encouraged in our efforts by Keith Sherman and his associates, Office of Planning and Programming, Illinois Department of Transportation. Finally, I would like to thank our two project monitors, William Murphy and Richard LaScala, for their efforts in administering this contract and their patience and good humour with regard to the completion of the final report.

The responsibility of the various authors of the report is indicated on the title page of each of the three parts. In each case, the first author was the faculty member responsible for the final product. I edited the entire report with the able assistance of Cynthia Griffin. We would like to thank Pat Griffis for her excellent work in producing the final version.

This research was a cooperative effort of faculty at two of the leading research universities in Illinois. It illustrates the benefits that can be achieved by pooling our research capabilities. Since the research was initiated in 1981, the mechanism for such collaboration has been formalized by the creation of the Illinois Universities Transportation Research Consortium by the University of Illinois at Chicago and at Urbana-Champaign, Northwestern University, Illinois Institute of Technology and the University of Chicago. Faculty members at these institutions look forward to future opportunities to serve the State of Illinois.

Urbana, Illinois	David E. Boyce
December 1982	Principal Investigator

PART I

PROSPECTS FOR THE DEMAND FOR ILLINOIS COAL IN EXPORT MARKETS

by

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Cynthia S. Griffin

CHAPTER 1

GLOBAL STEAM COAL DEMAND IN RELATION TO U.S. SUPPLY

1.1 Introduction

The purpose of Part I of this study is to evaluate prospects and determinants of the export market for Illinois coal and to identify trade barriers and necessary transportation investments. In order to pursue these objectives, four factors affecting the competitive position of Illinois coal in export markets were selected for detailed analysis:

1. quality requirements of export coal markets in relation to the characteristics of Illinois coal;

2. regulatory factors affecting export of Illinois coal;

3. transportation factors affecting export of Illinois coal;

4. price competitiveness of Illinois coal in export markets.

The organization of Part I is as follows. Chapter 1 discusses the worldwide steam coal demand outlook through the year 2000 and the potential U.S. share of the world steam coal market. To evaluate the competitive position of Illinois coal in export markets, the quality requirements of coal for current

international markets are examined in Chapter 2. Regulations concerning the use and shipment of coal in importing countries are discussed in Chapter 3.

Chapter 4 analyzes the existing transportation systems that connect Illinois mines to export ports and attempts to identify transportation barriers that may affect export of Illinois coal. The price competitiveness of Illinois in export markets is analyzed in Chapter 5. The delivered price of Illinois coal in export markets is compared with that of competitors. The chapter also identifies the probable range of delivered price reductions for Illinois coal that could be achieved through certain transportation improvements.

1.2 World Steam Coal Trade Prospects

Rapid increases in fossil fuel prices since the 1973 oil embargo, and insecure and diminishing supplies of oil have aroused global interest in the use of coal as an energy source. This interest extends to Japan and other fast-growing nations of the Pacific Rim, as well as traditional coal consumers in Western Europe. The U.S. has been a significant exporter of coal, particularly in the form of coking coal for metallurgical purposes. Presently, significant increases in demand for coal for production of steam for various uses, including electric power generation, are taking place. These increases result from the need to substitute coal for oil and natural gas in power generation, and the desire of both developed and developing countries to diversify their sources of energy supplies.

Based on a disaggregated analysis of coal use in each country by market sector (electric, industrial, residential, commercial and synthetic fuel) the World Coal Study [27,28] estimated that the world steam coal import

requirements by the year 2000 would be as high as 680 million tons of coal equivalent (mtce). This amount is approximately 750 million short tons. (Unless otherwise noted, all tonnage figures in this document are in short tons of 2,000 pounds/ton.)

The Interagency Coal Export Task Force [24] also projected a rapid growth in worldwide steam coal trade. Based on an analysis of each country's future economic growth, total primary energy consumption, consumption of electricity and the role of nuclear-generated electricity, the Task Force projected that worldwide steam coal imports for year 2000 would be 475 to 565 million tons. Their projections of steam coal imports by country and region are shown in Table 1.1. Since the Task Force report is the most recently published study, their projections are used as the basis for the following analyses.

Figure 1.1 shows the Task Force projection of steam coal imports by European and Pacific regions. Although the projected net growth between 1979 and 2000 is similar for both regions, a faster rate of growth was projected for the Pacific Rim region's import amounts. Japan's imports would increase to about 100 million tons, followed by about 50 million tons each required by Korea and Taiwan.

1.3 U.S. Share of the World Steam Coal Market

The steam coal market has been a buyers' market and the market is demand driven. Unlike coking coal, steam coal competes with other fuels such as oil, gas, nuclear energy, and hydroelectric power. In the past, the lower cost of coal relative to other fuels has been a major factor in selecting steam coal. U.S. steam coal could not compete with prices of coal from Poland and South Africa in the European Market. Asian buyers, including Japan, Korea and

Table 1.1

Steam Coal Imports by Country and Region

(millions of short tons)

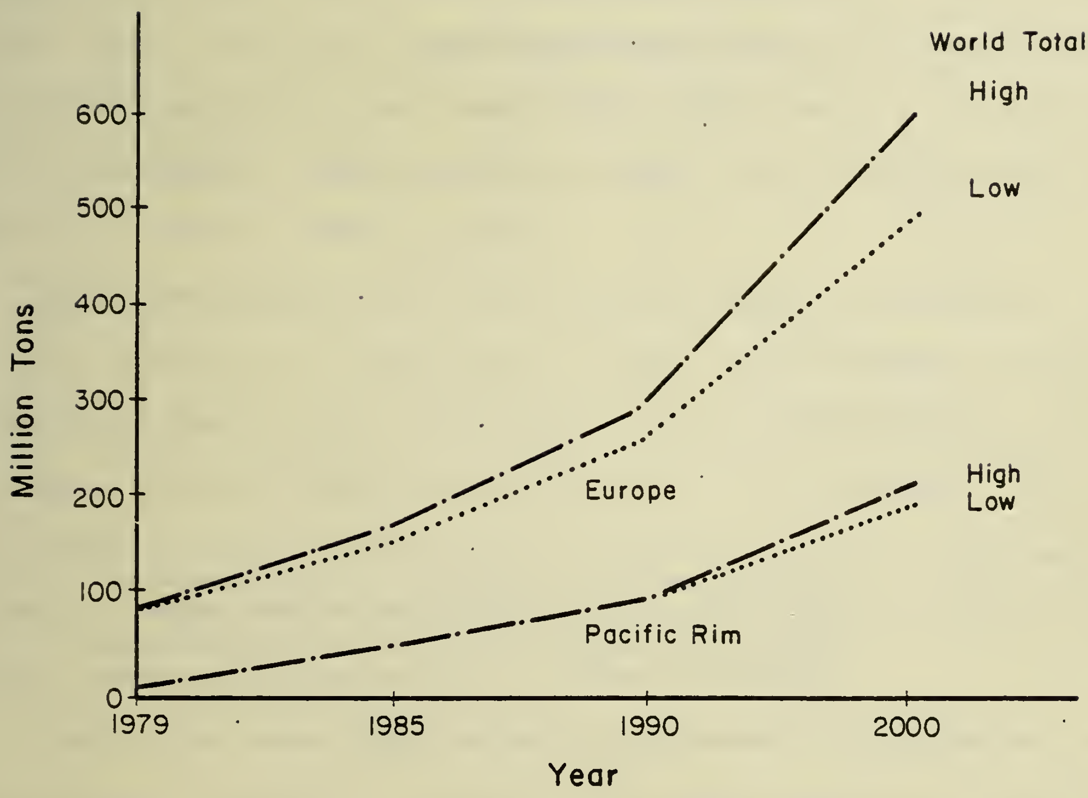
	1979*	1985	1990	2000
Europe				
Austria	3.0	4.8	6.3	17.1
Belgium/Luxembourg	5.8	12.7	17.3	27.6-33.4
Denmark	7.6	12.7	16.1	21.9
Finland	5.3	4.6-8.1	5.8-8.1	8.1-18.4
France	21.0	15.0-21.9	13.8-24.2	25.3-35.7
Greece	**	1.6	3.5	4.6
Ireland	1.1	2.2	4.0	7.1
Italy	2.1	17.3	36.8-41.4	46.0-54.1
Netherlands	2.6	6.6	15.1	33.0-37.4
Norway	**	0.8	0.9	3.1
Spain	3.6	6.9	9.2	24.2
Sweden	1.5	3.8	11.2	26.5
United Kingdom	2.0	0-8.1	0-8.1	0-10.4
West Germany	7.0	8.1-15.0	5.8-25.3	28.8-49.5
Subtotal	63	97-123	146-190	273-343
Pacific Rim				
Japan	2.7	25.3	48.3	98.9-118.5
Korea	5.9	9.2	16.1	50.6
Taiwan	5.3	3.5	16.1	41.4
Hong Kong	**	4.6	9.2	11.5
Subtotal	14	43	90	202-222
TOTAL	77	140-166	236-280	475-565

Note: One short ton is assumed to contain 24 million Btu.
* Observed; other years are forecasts.
** Unknown.

Source: U.S. Department of Energy [20].

Figure 1.1

Projection of Steam Coal Imports by Region



Source: U.S. Department of Energy [20].

Table 1.2

U.S. Steam Coal Exports

(millions of tons)

	1980	1985	1990	2000
Total[a]	15	34	64	197
Europe	14	28	49	145
France	3	4	5	9
Pacific Rim	2	6	15	52
Japan	1	4	7	27

Note: a. Excludes exports to Canada. U.S. coal exports to Canada in 1980 totaled 10.8 million tons; exports to other countries not mentioned totaled 0.7 million tons.

Source: U.S. Department of Energy [20].

Taiwan, preferred South Africa or Australia sources because of their lower prices.

Many analysts believe that future steam coal trade will be different. Demand for worldwide steam coal imports in the next decade is expected to exceed production from non-U.S. sources. The trend of world prices appears to be approaching those of the U.S. In July, 1981, CIF (cost, insurance and freight) quotations at ARA (Amsterdam-Rotterdam-Antwerp) for U.S. and South African steam coal market were between $76 and $81, while coking coal prices were at $76, making steam coal prices higher than coking coal for the first time. These higher prices might have resulted from the Polish supply problem and the coal miners′ strike in the U.S.

The United States′ share in the steam coal market in the Pacific region is also expected to increase due to buyers′ efforts to obtain security by diversifying supply sources, even though the delivered price of U.S. coal may be higher than its competitors. Moreover, the U.S. coal industry, one of the few competitive suppliers that is not owned and operated by a government, is viewed by buyers as a form of protection against sellers′ action to control prices, quantity, and destinations of their coal exports.

Based on the assumptions that (a) participation in the steam coal market is determined by price, (b) demand for worldwide imports will in the future exceed production from non-U.S. suppliers, and (c) the residual market will fall to the U.S., the Interagency Coal Export Task Force projected a rapid increase in the U.S. share of the world steam coal market in the year 2000. Table 1.2 shows 1980 and projected U.S. steam coal exports. These projections are slightly different from the Task Force projection. Recent efforts by Japan, Korea, and Taiwan to diversify their sources of coal are the basis for an upward adjustment in the Task Force projection [16].

1.4 Illinois Coal in Export Markets

There has been little Illinois coal exported to the world market. In fact, coal production in Illinois has not increased substantially in the past decade, despite constantly rising prices and increasing demand for steam coal worldwide. Among recent developments in global steam coal trade, however, there are at least two factors which support optimistic views on the future competitive position of Illinois coal in export markets. The trend of world steam coal prices, particularly in the European market, appears to be approaching production plus delivery costs of Illinois coal. Second, rapid increases in demand for steam coal imports in Europe have been pushing the port facilities on the Atlantic Coast toward higher levels for coal throughput. The result has been severe congestion and storage problems.

In the past price has been a major determinant of whether a producing region participates in the steam coal trade. Now, other factors such as sulfur, ash, and other charcteristics of coal must be considered because of the growing environmental concerns in various countries in the world. These factors are considered next in Chapter 2.

CHAPTER 2

QUALITY REQUIREMENTS FOR EXPORT COAL

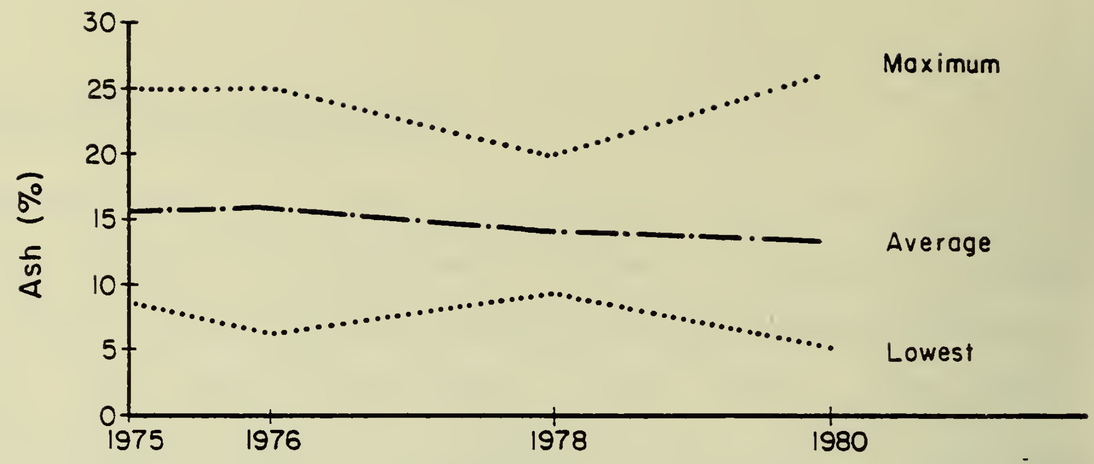
2.1 Quality of Steam Coal Consumed: The Case of Japan

Japan was chosen for this case study because the projected U.S. steam coal exports to Japan are large (27.2 million tons to Japan in year 2000 vs. 9.2 million tons to France, for example), and over 100 specifications of steam coal import contracts during 1975-1980 were readily available. The following five coal characteristics were chosen for the analysis of the quality of coal imported to and consumed in Japan:

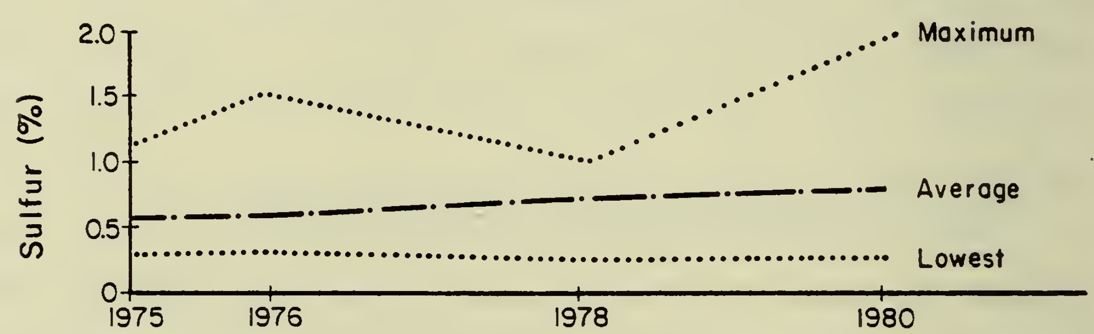
1. ash content
2. sulfur content
3. calorific value
4. total moisture content
5. combustible material

Figure 2.1(a) shows the trend of ash content in steam coal imported to Japan during the 1975-1980 period. While the average ash content decreased

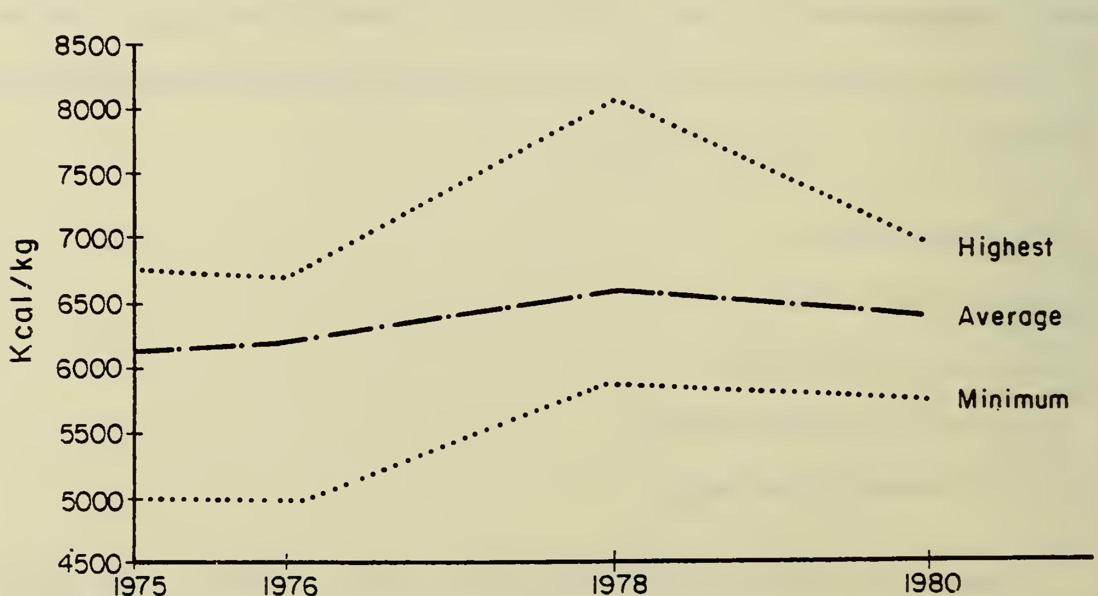
Figure 2.1



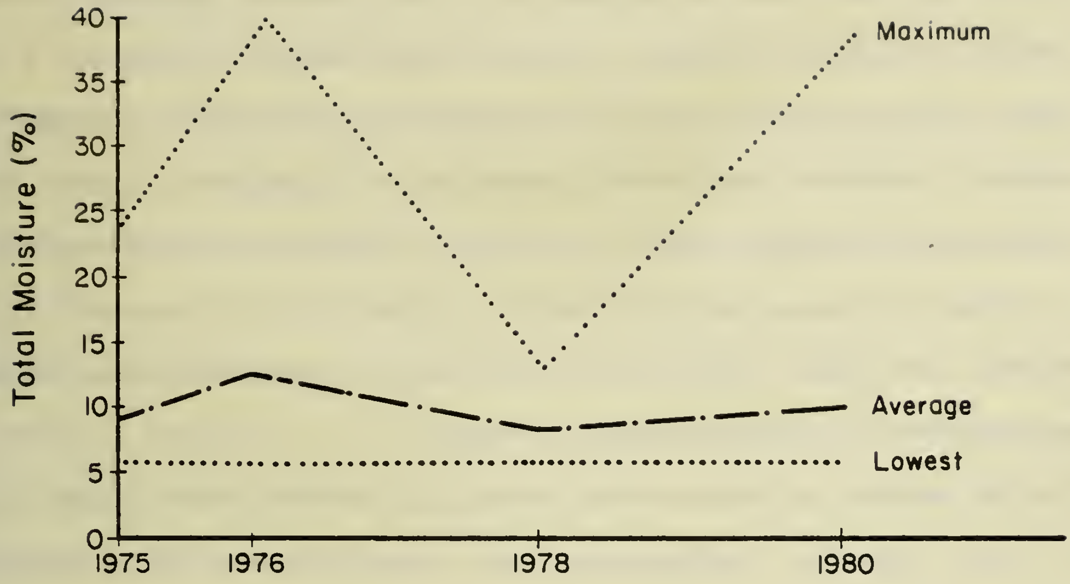
a) Quality of Steam Coal Imported to Japan, 1975-1980: Ash Content



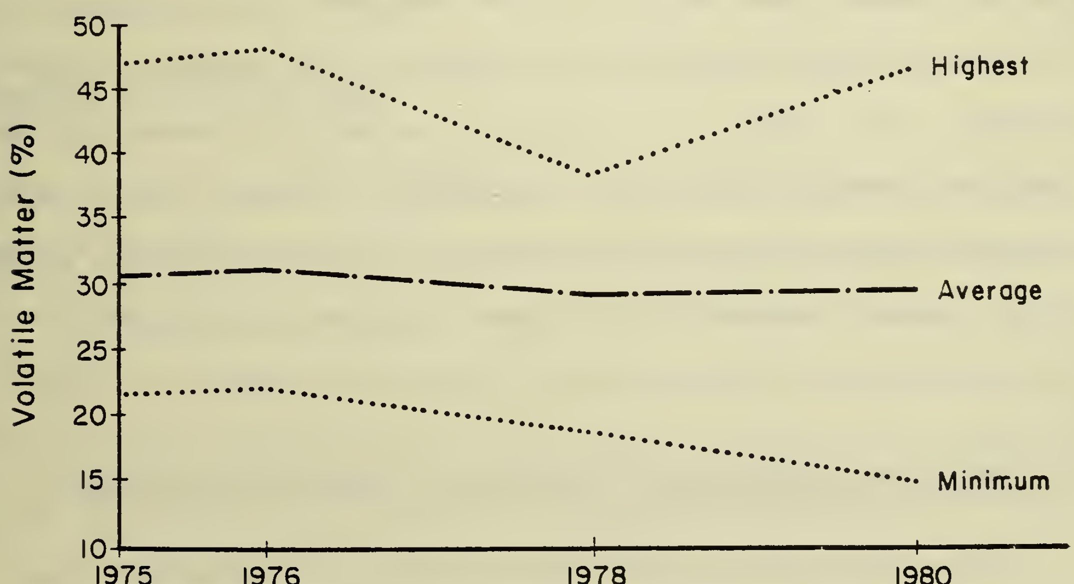
b) Quality of Steam Coal Imported to Japan, 1975-1980: Sulfur Content



c) Quality of Steam Coal Imported to Japan, 1975-1980: Calorific Value



d) Quality of Steam Coal Imported to Japan, 1975-1980: Total Moisture



e) Quality of Steam Coal Imported to Japan, 1975-1980: Volatile Matter

Source: Coking Coal Manual [4].

from 16 to 14 percent, the maximum ash content allowed increased from 25 to 27 percent. In general, however, Japanese buyers tended to prefer a low ash content because of potential disposal problems. Figure 2.2(b) shows the trend of sulfur content in steam coal imported to and consumed in Japan for the same period. The average sulfur content rose from 0.6 to 0.7 percent; likewise, the maximum allowable sulfur content rose from 1.2 to 2.0 percent for the same period. The high sulfur (1.5 to 2.0 percent) coal is believed to have been used in cement manufacturing and lime kilns.

The trend of calorific value content in imported coal to Japan is shown in Figure 2.1(c). Both average and minimum calorific values increased from 1975 to 1980. The average value fluctuates between 6200 Kcal/kg (11,000 Btu/lb) to 6,600 Kcal/kg (12,000 Btu/lb). Figure 2.1(d) shows the changes of total moisture content in steam coal imported to Japan during the same period. While the average total moisture content remained at approximately 10 percent, the maximum allowable content was as high as 39 percent. Figure 2.1(e) represents the changes in combustible material in steam coal imported to Japan. The average value shows a constant 30 percent, while the minimum allowable precent falls from 22 percent in 1975 to 16 percent in 1980. The maximum allowable percent was 47 percent during the same period.

2.2 General Requirements for the Quality of Steam Coal in Europe

Only a few of the contract specifications were available to the research team concerning European steam coal imports. Thus, this section deals with the general quality of coal required in Europe rather than the specific quality of coal that was analyzed for Japan in the previous section.

A major factor in coal quality purchasing decisions has been the historic pattern of consumption, influenced by the design of existing and planned boilers in Europe. Most European reserves are good quality steam coals, relatively low in sulfur. The historic pattern of consumption of good domestic coal influences customers in Europe to seek coals of comparable quality, as use of imported coal becomes more prevalent.

Utilities are anticipated to seek steam coal that is relatively low in sulfur content, generally 1.5 percent or less. Most of the European governments impose significant controls on sulfur levels and sulfur dioxide emissions; the implications of these controls is examined in Chapter 3.

2.3 Illinois Basin Coal: Quantity and Quality

2.3.1 Quantity of Illinois Coal

Illinois has the largest identified total bituminous coal resources (approximately 161 billion tons) and the largest surface bituminous coal resources suitable for strip mining of any state in the United States. Of the 20 coal seams that have been mined in Illinois, most of the production has come from eight coal seams, with 85 to 90 percent of the total production coming from the Herrin (No. 6) and the Springfield-Harrisburg (No. 5) coal seams.

Of the 161 billion tons of total coal resources, about 40 percent (66 billion tons) are currently mineable and classified within Illinois′ coal reserve base. A little more than 90 percent (60 billion tons) are classified as underground reserves. About six billion tons have been classified as

surface reserves which are coal seams greater than 18 inches in thickness and with less than 150 feet of overburden.

In 1980, Illinois had a total of 55 coal mines (31 underground and 35 surface) that produced a total of 62.5 million tons (35.0 million underground and 27.5 million surface), ranking fifth in terms of national coal production, and exceeded only by Kentucky, West Virginia, Wyoming, and Pennsylvania. Underground mining accounted for 47 percent of all mines, 56 percent of the tonnage, and 72 percent of the employees.

2.3.2 Quality of Illinois Coal

It is well-known that the major problem facing the coal industry in Illinois is the high sulfur content of its coal. According to the Illinois Geological Survey, about 97 percent of the state's coal resources contain over 2.5 percent sulfur. Only 2.5 percent of the Herrin Seam (No. 6), containing over 42 percent of the identified resources in Illinois, has a sulfur content of 2.5 percent or less. Only 5.4 percent of the Harrisburg-Springfield Seam (No. 5), containing over 31 percent of the identified resources in Illinois, has a sulfur content of 2.5 percent or less. Table 2.1 identifies Illinois coal resources by sulfur content. The reserve base of Illinois coal by sulfur content is shown in Table 2.2. Overall remaining low and medium sulfur coal reserves (less than three percent) is approximately seven billion tons, of which 695 million tons is classified as surface.

Calorific values of Illinois coal reserves typically range from 9,000 Btu/lb (5000 Kcal/kg) to 13,000 Btu/lb (7,000 Kcal/kg). As shown in Table 2.3, the majority of Illinois coal falls into 10,000 Btu/lb to 11,000 Btu/lb category. Ash content is irregular and unpredictable for large areas of

individual seams. Typical Illinois coal falls into the 9-12 percent category, as shown in Table 2.4. Local variations commonly occur on the order of 2-3 percent. The estimates in Tables 2.3 and 2.4 are approximated from various published data,

The coal characteristics summarized above provide a basis for assessing the potential of Illinois coal for export. The calorific values and ash content levels of Illinois coal are variable to the extent that they would not be constraining factors in export markets. Low sulfur coal of less than 1.0 percent, however, accounts for only 0.2 percent, or 122 million tons, of Illinois′ reserve base. However, considering that sulfur content in steam coal imported by Japan is increasing and the maximum allowable sulfur content of steam coal imported to Japan in 1980 was two percent, the possible utilization of medium sulfur reserves (between 1.5 percent to 2.5 percent) in the near future could substantially increase the total export coal reserve base in Illinois by an additional 4.5 billion tons.

The mechanical cleaning of coal has the potential of reducing the ash content and increasing the calorific value of coal. It also has the ability to remove the pyritic sulfur from high sulfur Illinois coal, reducing total sulfur contents by as much as 50 percent. Reductions to the equivalent of 2-3 percent sulfur coal are possible. Washed coals could be blended with low sulfur coals to meet specific sulfur standards in European countries. In addition, new developments in blending techniques and possible implementation of pollution control technology in foreign markets could result in a greater demand for Illinois coal in the future.

Table 2.1

Illinois Coal Reserves by Sulfur Content

Sulfur Content (percent)	Percent of Total Reserves 0.7-2.5	2.5-5.3	over 5.3
Statewide	3	72	25
Herrin (No. 6)	3	64	33
Harrisburg-Springfield (No. 5)	6	80	14

Source: Illinois Geological Survey Memorandum [8].

Table 2.2

Illinois Coal Reserves Greater Than 28 Inches Thick by Sulfur Content (billions of tons)

	Sulfur Content (percent)							
	0.7-1.4	1.5-1.8	1.9-2.2	2.3-2.6	2.7-3.0	>3.0	Unknown	Total
Deep Minable	0.67	1.19	1.38	1.67	1.49	36.17	10.88	53.44
Strip Minable	0.01	0.05	0.09	0.18	0.36	10.21	1.32	12.22
Total	0.68	1.24	1.47	1.85	1.85	46.37	12.20	65.67
Percent	1.1	1.9	2.2	2.8	2.8	70.6	18.6	100.

Source: U.S. Bureau of Mines [17, p. 410].

Table 2.3

Illinois Coal Reserves by Calorific Value

Btu/lb (1,000's)	Percent of Total Reserves 9 - 10	10 - 11	11 - 12	12 - 13
Statewide	11	56	24	9
Herrin (No. 6)	2	63	29	6
Harrisburg-Springfield (No. 5)	0	66	12	22

Source: Keystone Coal Industry Manual [12].

Table 2.4

Illinois Coal Reserves by Ash Content

Ash Content (Percent)	Percent of Total Reserves 3 - 6	6 - 9	9 - 12	12 - 15
Statewide	4	37	56	3
Herrin (No. 6)	0	39	58	3
Harrisburg-Springfield (No. 5)	0	28	72	0

Source: Keystone Coal Industry Manual [12].

CHAPTER 3

REGULATORY FACTORS AFFECTING THE EXPORT OF ILLINOIS COAL

There are numerous regulatory factors that could constrain Illinois' coal export potential. These exist in the form of environmental and transportation standards in importing countries. Coal sulfur content and sulfur emission regulations are the most critical environmental factors determining demand for imported coal. It would be extremely difficult, however, to be precise about detailed impacts that specific regulations and standards would have on the demand and use of imported coal. Thus, this study has been confined to a general comparative analysis of regulatory standards in all such foreign markets, particularly in France and Japan. Transportation regulations and policy are then discussed in terms of the potential constraints they pose for transporting coal from foreign ports to generating stations.

3.1 Environmental Regulations in Importing Countries

As noted in Chapter 2, coal quality is a major concern in importing countries. This concern is partly based on compliance with environmental regulations, particularly those restricting sulfur dioxide emissions.

Regulatory compliance varies with each importing country, but it is usually based on the emission tolerance levels and historic consumption patterns.

In some of these importing nations, regulatory authority is shared by local jurisdictions and the national government; in others, it is totally centralized. Some countries have created "protected zones" in certain industrial and rural areas, in which utilities and industry agree to adhere to stricter standards, either at all times or during pollution alerts.

Table 3.1 identifies several European countries that have employed one or more of these regulatory controls on sulfurous emissions. Nation-wide use of low sulfur coal, emission limitations, and the implementation of planning programs have been the preferred means of control. These control strategies are in some cases considerably more stringent than in the U.S.; however, the extent to which European countries have succeeded in meeting ambient air quality standards through the implementation of these control strategies has not been documented.

Foreign governments usually impose two types of controls on combustion emissions resulting from coal use. These are (a) sulfur tolerance levels or sulfur dioxide emission limitations, and (b) implementation of pollution control systems. Controls on sulfur emissions take several forms. The major limitation, though, has been on the sulfur content of the fuel. Most European countries limit coal sulfur content to 2.0 percent. The major exception is Greece, which has a maximum sulfur content of 3.0 percent. Preferred levels, though, generally range from 1.0 to 1.5 percent. Table 3.2 summarizes the coal sulfur specifications for European and Far Eastern coal markets.

Higher sulfur levels are acceptable for use in the cement and lime industries in both Western Europe and the Far East. In some countries, restrictions are less stringent for industrial uses than for utilities; higher

Table 3.1

Legislative Controls on Sulphurous Emissions in Some European Countries

	Planning	Investment Decisions	"Polluter Pays"	Financial Incentives	Nuisance & Health Laws	"Alert" Periods	Low S Fuel, Nationwide	Low S Fuel, Protected Zones	Low S Fuel, "Alerts"	Flue Gas Desulfurization	Emission Limits	Air Quality Criteria
Austria							?					X
Czechoslavakia	?		?					X	X		?	
Denmark	X			X			X	X				
Finland	X				X		?				?	?
France				X		X	X	X	X			
Germany (F.R.)	X					X	X			X	X	
Great Britain	X			X	X		X	X			X	
Hungary	X	X	X					X			X	X
Ireland	X						X					
Italy							X				X	X
Luxembourg							X					
Netherlands							X			X	X	
Norway	X		?				X	X		X		
Poland		X	?								X	
Soviet Union	X		X								X	X
Sweden							X	X				
Switzerland							?					
Yugoslavia		X	X		X						X	

X Implemented wholly or partially
? Implementation under consideration

Source: R. A. Barnes [1, pp. 1219-23].

Table 3.2

Coal Import Specifications for Sulfur Content

Maximum Percent by Weight

Europe	
Norway[1]	1.5
Sweden[2]	0.6 - 0.8 (maximum)
Finland[3]	-
Denmark[4]	1.5 (1.0 preferred)
West Germany	1.3
Belgium/Luxembourg	2.0 (1.0 preferred)
Netherlands[5]	0.3 - 1.2
United Kingdom	2.0 (1.5 preferred)
Ireland	2.0 (1.0 preferred)
France	2.0 (0.4 - 1.5 preferred)
Italy	1.0
Spain[6]	1.0 - 1.8
Greece	3.0
Far East	
Japan[7]	1.0
Taiwan	1.5 (Air dried)
South Korea[8]	1.0
Hong Kong	-

Notes:
1. 1.0 probable maximum for electricity generation
2. From proposed environmental regulations
3. Finland has relied almost totally on low-sulfur Polish coal so there has been no need for restrictions.
4. At 10,800 to 12,000 Btu/lb net or 11,300 to 12,600 Btu/lb gross.
5. 1.8 percent can be used if blending to 1.0 percent overall is possible.
6. 2.5 percent maximum for industrial use.
7. 2.0 percent maximum acceptable for cement manufacturing.
8. 1.5 percent - 3.0 percent acceptable for cement manufacturing.

Source: Roger W. A. LeGassie, [9].

sulfur levels can be used, but only under special circumstances: (a) where the Btu value is high and sulfur is within acceptable limits, (b) where the sulfur can be absorbed in combustion processes, such as in the cement industry, or (c) where coal may be obtained at a discount for blending with low sulfur coal.

Zinder-Nerris, Inc. recently polled several European coal-importing nations on the prospects of using high sulfur coal in Europe. The results are summarized in Table 3.3. Foreign demand for high sulfur coal does exist, but quantities are determined by sophisticated blending procedures and liberal discounts for high sulfur coal. Nearly all countries polled expressed an interest in high sulfur coal for cement manufacturing.

Limits on emissions from existing plants, overall nationwide emissions, and "tall stack" or other design and equipment requirements have been instituted in several West European nations and in Japan. These control systems vary widely, as shown in Table 3.4. Most of the countries have explicit requirements for emission limitations or for the sulfur levels in the fuel. Most countries also regulate stack heights to limit ambient concentrations. Japan relies almost exclusively on specified stack height criteria; France, in addition to stack height criteria, has a rigid structure of coal sulfur limitations and individual plant emissions delineated according to specially "protected zones". Stack height criteria, are an effective means of reducing local concentrations of sulfur dioxide emissions. Currently, no legislation has been enacted to control long-range transport of emissions.

Implementation of pollution control systems has received much attention in the United States. Industrial and utility applications of flue gas desulfurization (FGD), though, has been growing slowly in the European countries. No country has made a full commitment to FGD technology, as Table

Table 3.3

Prospects for Use of High Sulfur Coal in Western Europe*

	Denmark	Italy	Sweden	Germany	Spain	France
What is the acceptable limit of sulfur for utilities?	2.0%	1.0%	0.8%	1.0% utilities 1.5% to 2% for industry	1.5%	1.0% 2.0% if very high Btu
Will utilities buy cheaper high sulfur coal for blending?	Yes, but not all have mixing capa-bilities	To a limited extent	NA	Almost unknown in Germany	Many will if facilities available	Yes, if volitility is roughly equal
What discount is required on high sulfur coal for blending by utilities?	10%	2% for each 0.1% of sulfur over 1.0%	NA	Price discount immaterial in view of anti-pollution laws	Sufficient to offset extra costs	Must cover all costs of blending
What industries will take high sulfur coal? How much?	Cement: 100,000 tons annually of 2.5% sulfur	Cement: 1 million 1980. 2.5 m. 1985. 5 m. 1990.	Cement: 200,000 tons now, 300,000 tons 1985. Pulp: 300,000 tons maximum	Only cement, but estimated discount $4 per ton required	Cement: 30% of steam requirement	Cement: 2.3% to 2.5% sulfur
What are prospects for scrubbers, fluid bed units, etc.?	Limited	Studies under-way, results unknown	Will be used but only for coal with maximum 2% sulfur	Technical inprovements may encourage future demand, but in long term, high sulfur coal will not exceed 5% of total coal use	Utilities will avoid expense of scrubbers and other high cost facil-ities	Utilities are not using scrubbers and have no plans for their use

*Response by Zinder-Nerris correspondents in Western Europe, May 1981.

SOURCE: Wilson-Smith [24].

Table 3.4

Sulfur Dioxide Emission Regulations or Guidelines Applicable to Industrial Boilers

Country	Solid Fuels
England	Specified stack height to limit short term ambient concentration (nominal 3 min avg $\leq$ 0.17 ppm SO)
France	Stack height criteria Rhone Zone: $\leq$ 1%S in fuel Paris and North Zone: $\leq$2 g SO_2/th (2.2 lbSO_2/MBtu) Power plants: Lowest %S if ambient SO_2>1000μg/m^3
Germany	$\leq$4 TJ/hr thermal input (1100 MWt): $\leq$1% S $\geq$4 TJ/hr: 2.75 gSO_2/KWh (1.7 lbSO_2/MBtu) Plus specified stack height to limit ambient concentration
Japan	Specified stack height: SO_2(vol/hr) = $K\times10^{-3}H_e^2$ (3<K<17.5, depending on region)
Norway	Unknown
Spain	Bituminous or anthracite: Power plant: 2400 mg/Nm^3 Other comb: 2400 mg/Nm^3 Lignite: Power plant: 9000 mg/Nm^3 Other comb: 6000 mg/Nm^3
Sweden	Unknown
USA	New steam generators >73.3 MWt (250 MBtu/hr heat input): 520 ng SO_2/J (1.2 lb/MBtu) All other boilers: applicable state regulations[a] New steam electric power plants >73.3 MWt input: SO_2 reduction (30da avg) of: 70% below 260ng/J (0.6 lb/MBtu) 90% below 520ng/J (1.2 lb/MBtu)

Note: [a] A federal standard for new industrial boilers is expected in 1981. Current state regulations are equivalent to approximately 2.5 lb SO_2/MBtu thermal input.

Source: E. S. Rubin [25].

3.3 shows. In fact, in 1978, only six full-sized FGD installations existed in Western Europe, three in Germany, and one each in Norway, Sweden, and France. The technology is still viewed as too costly and technically unproven for widespread application. Japan is the major exception. It is regarded to be one of the most advanced countries in developing environmental control systems. Limestone type flue gas desulfurization units have been operating successfully since 1967. Dry type FGD systems are in the development stage, and they are expected to come on line in 1982. Despite its commitment to FGD technology, Japan's upper limit for sulfur content is still 1.0 percent because of ecological and social perception problems surrounding disposition of the ash and sludge material from FGD operations.

Fluidized bed combustion (FBC) technology has also attracted similar interest internationally because of its efficient sulfur removal at low cost. For the most part, though, full-sized units are still in the planning stages, and it is unlikely that full commercialization will occur before 1990. The exceptions have been Denmark and Japan. Small-scale five-to-ten megawatt fluidized bed pilot plants are being studied or are under consideration.

Utility plant siting and licensing requirements could weaken import coal demand. These requirements should not be a major constraint, however, in Western European countries. France has a nationalized utility industry, and even though public hearings are held, decisions concerning when and where to build utility generating stations are made at the discretion of the government. Japan, though, has strict siting requirements that could significantly weaken import coal demand. Currently, Japanese policy on fishing rights and water quality takes precedence over energy issues, and utility siting decisions are made assiduously.

The primary objective of coal importing countries has been to control coal sulfur emissions rather than to encourage use of high sulfur coal. The primary control strategies have been the institution of sulfur tolerance levels or sulfur emission limitations, either through stack criteria or regional/national ambient air quality standards. Nevertheless, importing countries are likely to take more high sulfur coal in the future when full commitment to pollution control systems is achieved. Increased use of coal in cement manufacturing will add to this increased demand. The combination of blending strategies and washing techniques could reduce Illinois' coal sulfur levels to 1-2 percent, acceptable to most European and Far Eastern markets.*

3.2 Transportation Regulations in Importing Countries

Coal transshipments by rail and barge from port terminals are governed by transportation policy and regulations. In Europe, transportation regulatory procedures are similar to procedures in the United States. Specialized tariff rates and private agreement provisions for rail carriers exist. Apart from additional rate increases and time delays during transshipment, they are not considered to be a serious problem. Although it could be perceived to be more as an environmental constraint, blowing of coal dust during rail transshipments is a serious problem which is heavily regulated. Japanese regulatory procedures also are similar to procedures in the United States.

* Following completion of this text, it was pointed out to the authors that high chlorine content may be another serious drawback of using Illinois coal in connection with FGD systems.

New technological requirements related to rail and barge shipments have initiated government responses for regulatory intervention. Spontaneous combustion of coal during shipment in Japan has necessitated government requirements for technological innovations to control this problem.

CHAPTER 4

TRANSPORTATION FACTORS AFFECTING EXPORT OF ILLINOIS COAL

One of the most prominent factors that will determine the level to which Illinois will participate in the growing world demand for U.S. coal reserves is the condition and capabilities of the present and future transportation system including rail, barge, truck, and port facilities. Most of the variation in steam coal price lies in transportation costs. Port terminals, free of congestion and delays, are particularly critical for developing an increased share of the world coal export market.

Currently, coal is transported within and from Illinois by three transportation modes: rail, barge and truck. Illinois' proximity to the Mississippi and Ohio Rivers, in combination with the existing well-connected Midwest rail network, makes it reasonable to consider Gulf Coast ports to be the natural egress points for Illinois coal exports. Historically, the inland transportation system has handled comparitively small amounts of export coal to the Gulf Coast or to the Pacific Coast port terminals. However, as severe port congestion and the resulting increase in time delays and demurrage charges on the Atlantic Coast persist, more attention has been directed toward the use of the existing transportation network from Illinois to both the Gulf and Pacific Coasts.

This chapter, therefore, has three objectives. First, transportation facilities for moving Illinois coal are identified in terms of their potential role for serving an increased coal export market. Major limitations and physical barriers are identified in terms of their importance and impact on coal shipments. Second, an examination of the ocean port terminal facilities serving the Illinois coal market is made. Coal handling capacities and critical factors affecting movements of coal through port facilities are examined. Third, factors affecting oceanborne coal transportation are inventoried.

4.1 Domestic Transportation Systems

4.1.1 Rail Network Characteristics

The development of the coal resources in Illinois is greatly dependent upon the quality of rail service to the coal-producing regions. Because of its central geographic location between the agricultural West and the industrial East, Illinois has become an important gateway state with a railroad network of over 10,000 route-miles. Of the 34 railroads that own trackage in Illinois, four railroads transport significant amounts of coal, usually by one or more unit train operations. Unit trains usually consist of 100-110 hopper or gondola cars with each car capable of holding 100 tons of coal. Other railroads operating in the state handle individual or multiple carloads of coal by conventional freight transport.

The four principal coal-hauling railroads are the Illinois Central Gulf, the Burlington Northern, Conrail, and the Missouri-Pacific. They annually

haul more than 32 million tons of coal inter- and intrastate. The role of Conrail in Illinois has been declining, however, leaving only three rail carriers to provide the majority of rail service to the coal-producing regions. The Illinois Central Gulf, the Burlington Northern, and the Missouri-Pacific route-mileage in 1980 was 2445, 1387, and 645 miles, respectively. Cumulatively, these railroads own approximately 45 percent of rail route-mileage in Illinois.

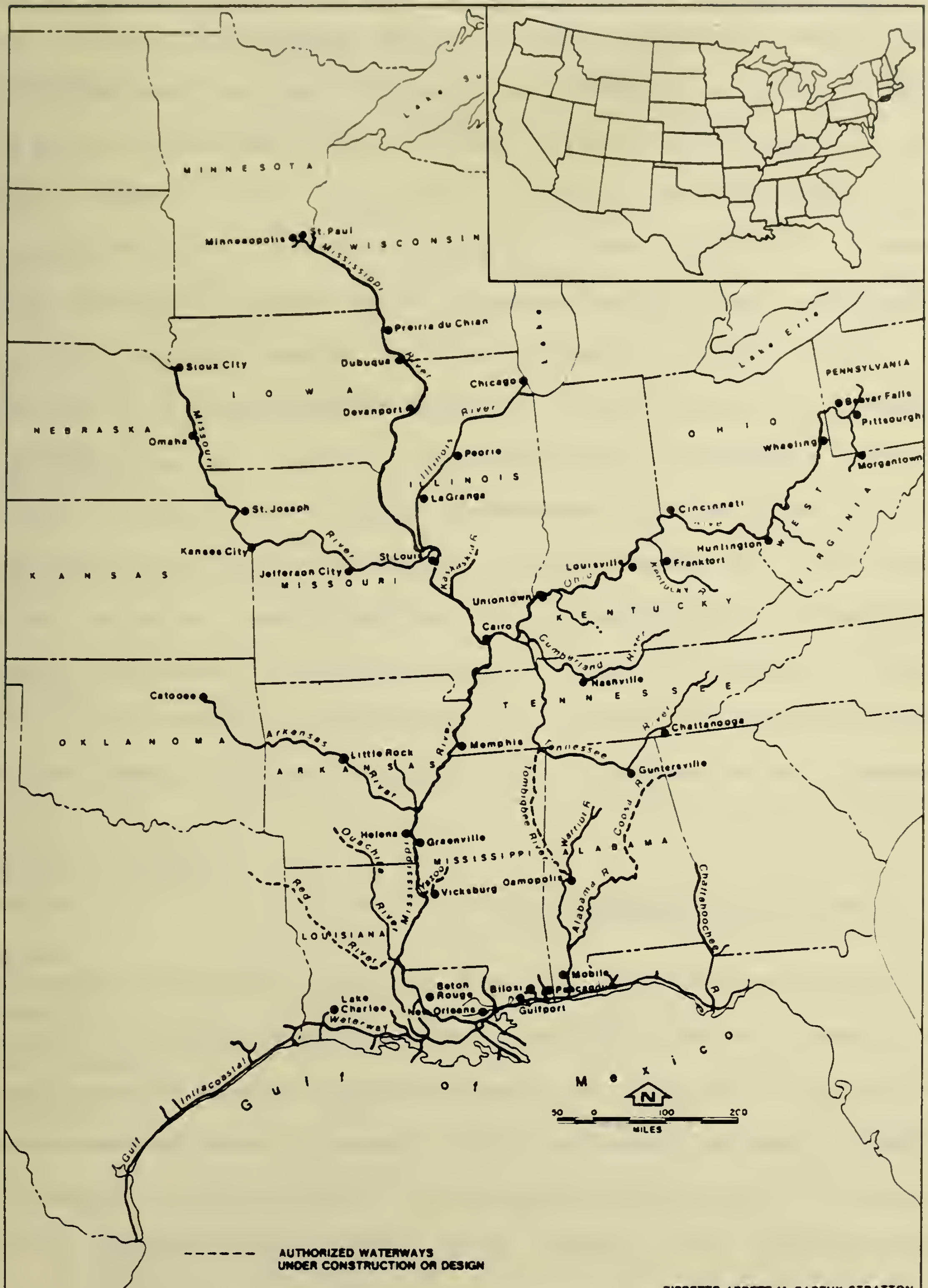
4.1.2 Inland Waterway Characteristics

Illinois' proximity to two of the major inland waterways in the United States, the Mississippi and the Ohio Rivers, facilitates inexpensive movement of coal by barge to Gulf ports. The location of these rivers is shown in Figure 4.1. The Illinois River and its tributaries in west-central and northeastern Illinois provide an inland waterway connection between the Mississippi River and Lake Michigan. The potential role of the Illinois River in barge transportation for coal exports, however, is relatively minor. Port terminals on the Illinois River serve primarily as receiving points for intra- and interstate rail shipments of coal, which is usually shipped by barge to Chicago and other Great Lakes cities for electric power generation.

The Kaskaskia River is expected to play an important role in Illinois and Midwest coal exports. The U.S. Army Corps of Engineers, in 1976, completed dredging a 30-mile length of the Kaskaskia River, facilitating barge transportation. Further dredging from New Athens to Fayetteville is expected to be completed by 1984, extending barge service an additional six miles, and opening up an additional four billion tons of coal reserves to barge service.

Figure 4.1

Mississippi Basin Inland Waterway System



Source: U.S. Department of Commerce [19, p. 10].

Port terminal characteristics are listed in Table 4.1. The terminals' total annual throughput capacity in 1981 exceeded 48 million tons of coal. Storage capacity is at least 4.5 million tons. Cora Coal Transfer Facility at Cora, the Kaskaskia Regional Port District Dock at New Athens, and the Kellogg Coal Transfer facility at Sparta possess the greatest annual throughput capacity, 15 million tons, 10 million tons, and 8.8 million tons of coal, respectively. Due to winter closings of river ports and terminals north of St. Louis, use of all-season ports in southern Illinois is necessary to facilitate year-round access to the inland waterway system. In addition to the Cora, Kaskaskia, and Kellogg coal terminals on the Mississippi, the Peabody terminal and the Shawneetown Regional Port District Terminal at Shawneetown, the Downen Brothers Transportation facility at Rosiclare, and Cook Terminal at Metropolis, all on the Ohio River, serve as rail-water transfer facilities for coal. Coal transportation from southern Illinois to Mobile, Alabama, is expected to significantly advance Illinois' export potential with the completion of the Tennessee-Tombigbee Waterway.

4.1.3 Motor Carrier Characteristics

Significant amounts of coal are transported in Illinois by truck linking coal mines with rail tipples and barge terminals. Typical net capacity of coal trailers is 22 tons. The primary advantages of truck transportation are related to speed and route flexibility. The use of trucks may have economical advantages for mines with relatively small production output, shipments over short distances (1-10 miles), mines lacking railway siding access, and utilities lacking railway siding access.

Table 4.1

Major Illinois Coal Export Terminals on the Inland Waterway System

Coal Terminal	Maximum Annual Capacity (thousand of tons)	Storage Capacity (thousand of tons)	Delivering Carrier*
Havana Coal Transfer Plant Havana, IL	6,240	140	BN
AMAX Coal Co. Frederick Dock Frederick, IL	550	0	BN
Peabody Coal Co. East St. Louis, IL	5,000	0	ICG,BN
Kellogg Coal Transfer Terminal Sparta, IL	550	320	MP
Cora Coal Transfer Facility Cora, IL	15,000	1,000	MP
Kaskaskia Regional Port District Red Bud, IL	10,000	0	ICG
Peabody Coal Co. Shawneetown, IL	5,500	200	Truck
Shawneetown Regional Port District Terminal Shawneetown, IL	1,000	1,000	Truck
Downen Bros. Transportation Rosiclare, IL	1,500	1,000	ICG;Truck
American Electric Power Co. Metropolis, IL	3,000	1,000	BN,ICG,MP
TOTAL	48,340	4,660	

*Notes: 1. Burlington Northern - BN
2. Illinois Central Gulf - ICG
3. Missouri Pacific - MP

Source: Keystone Coal Industry Manual [12].

4.1.4 Slurry Pipelines

The role of slurry pipelines as a major transportation mode for Illinois coal exports, is still in the planning stages, but the export potential of coal slurries is indicated by the Coalstream Pipeline Company's proposal to construct a 1,500 mile pipeline from southern Illinois to Florida for domestic and export use. Capacity potential for Illinois exports has been projected at 25 to 55 million tons/year.

4.1.5 Great Lakes - St. Lawrence Seaway

Great Lakes colliers have been a viable mode of transportation of coal to other states and Canada; however, this transportation route is not expected to play a major role in coal exports to countries other than Canada. Physical, geographical and weather conditions severely constrain the use of the Great Lakes-St. Lawrence Seaway route for coal exports.

The Seaway system, in its present form, limits the maximum dimensions for vessels to 730′ length, 75′6" beam and 26′ draft. At these dimensions, Canadian lakers can carry approximately 28,000 tons, and U.S. vessels can accommodate 22,000 tons. Coal can move from Great Lakes ports via lake vessel to a river port, and then be off-loaded and reloaded onto a larger size ocean vessel at Quebec City. This procedure, however, has a high cost because of the transfer charges and the cargo tolls.

Operation on a seasonal basis is an additional limitation. The St. Lawrence Seaway System generally has been operated only from April 1st to December 15th. Most Illinois mines are better served by inland river systems which are relatively free of weather constraints since they are located in

southern Illinois. Draft restrictions, weather constraints and tolls all may result in conditions that tend to preclude Great Lakes-St. Lawrence transportation.

4.2 Inland Transportation Factors Affecting Illinois Coal Movements

The export potential of Illinois coal is not constrained by lack of adequate transportation infrastructure and services in Illinois. There are institutional factors, however, that could potentially hinder Illinois coal exports. These factors are examined next.

4.2.1 Rail System Viability

In the past decade, rail freight service has declined in Illinois as a result of the bankruptcies of two railroads -- the Rock Island (Chicago, Rock Island, and Pacific) and the Milwaukee Road (Chicago, Milwaukee, St. Paul and Pacific). These failures have affected service over 820 miles of the state's rail system. Abandonment of individual light-density rail lines from May 1, 1978 - May 1, 1980 totaled 1,194 route-miles. Abandonment is under consideration for an additional 1,020 miles of lines.

The financial condition of the state's major coal railroad carriers has been a contributing cause for line abandonments. Conrail and the Illinois Central Gulf, which lost more than $487 million and $32 million in 1979, respectively, have been given a triple B rating by Standard and Poor's, an indication of declining investment potential by the financial community. The Milwaukee Road and the Chicago and Northwestern, had similar losses of $105 million and $37 million, respectively.

Poor railroad finances and abandonments have spurred mergers. Five mergers may affect Illinois rail service with further rail line abandonments. The status of these mergers is as follows:

1. Burlington Northern/St. Louis-San Francisco - final
2. Chessie/Seaboard Coastline - final
3. Norfolk and Western/Southern - final
4. Union Pacific/Missouri Pacific/Western Pacific - final

These carrier abandonments and mergers may be expected to result in a major restructuring of the rail system. Mergers may result in new investments and improved service as well as abandonments and downgrading of some lines. These changes may be expected to have long-term effects on the viability of the rail carriers and the efficient movement of coal on the rail system.

4.2.2 Locks and Dams

A primary constraint on efficient coal barge movements on the Mississippi and Ohio Rivers has been bottlenecks and congestion at locks and dams. Figure 4.2 identifies the locks and dams on the inland waterway system. Locks and dams bordering Illinois extend from Lock and Dam 12 at Belleville, Iowa to Locks and Dam 27 at St. Louis. Below St. Louis, the Mississippi is lock-free. Locks and dams on the Ohio River bordering Illinois formerly began with Lock 50 above the mouth of the Wabash River near the Illinois-Indiana border. Three additional locks and dams (51-53) are located above the Ohio's mouth at Cairo. Locks and dams 50 and 51 have been replaced by the new Smithland Locks. Studies are being conducted to determine whether Locks 52 and 53 should be improved or replaced by the authorized Mound City Locks and Dam.

Figure 4.2

Constraining Locks

Source: U.S. Department of Commerce [19].

Table 4.2 presents capacity characteristics of the constraining locks on the inland waterway system. Locks and Dam 26 at Alton, Illinois is considered to be the only major capacity problem for coal barge shipments originating north of St. Louis. Capacity is expected to be reached by 1984, and current bottlenecks are at least 24 hours in each direction, costing waterway industries approximately $4,000 per day in each direction. The impact of this constraint on coal barge exports is expected to be minimal, however, because the majority of the coal export terminals are located south of St. Louis and along the Ohio River.

4.2.3 Waterway User Charges

In October, 1978, the Inland Waterways Revenue Act of 1978 was enacted. The act imposes a user tax on fuel used in commercial transportation on the inland waterways in accordance with the following schedule:

October 1980 - September 1981	4 cents/gallon
October 1981 - September 1983	6 cents/gallon
October 1983 - September 1985	8 cents/gallon
After September 1985	10 cents/gallon

The user charges are designed to recover Federal operation, maintenance, and repair expenses for locks and dams. It has been projected that these user charges will eventually result in a decline of ten percent of total coal traffic on the inland waterway system, with the lost traffic being shifted to the railroads.

Table 4.2

Characteristics of Constraining Locks

Waterway	Lock and Dam	Estimated Annual Capacity	1976 Waterborne Demand		Year Capacity Is Reached
			(Millions of tons)		
Illinois	Marseilles	32	25.8		1983
	Starved Rock	36	27.2		1985
	Brandon Road	32	23.1		1989
	Dresden Island	35	25.4		1989
	Lockport	33	22.5		1992
	Peoria	57	33.2		1994
	LaGrange	59	30.7		1998
Tennessee	Kentucky	31	21.8		1991
Ohio	Gallipolis	47(a)	33.8	(1975)	1996
Mississippi	L&D 26	73(b)	54.5		1984
Gulf Intracoastal	Inner Harbor	30	30.4		Current
	Port Allen	30	20.2		1993
	Vermilion	45	40.3		1996

Note: a. Two-directional, based upon U.S. Army Corps of Engineers, Waterborne Commodity Statistics.

b. Practical capacity estimate prepared by Corps of Engineers.

SOURCE: U.S. Department of Commerce [19].

4.2.4 Highway Deterioration

A serious problem in highway transportation of coal has been road deterioration as a result of heavy coal truck movements. The Coal Haul Roads Study, prepared for the U.S. Department of Transportation, Federal Highway Administration, indicated that the cost of reconstructing and improving the entire Illinois coal road system to full standards was $192.6 billion (1977 dollars). This system includes interstate, primary, and secondary roads. Repairing pavement deficiencies on primary and secondary roads was estimated to cost $37 billion.

Coal severance taxes, implemented in numerous coal producing states to provide funds for road repair, have not been instituted as a separate tax in Illinois. Funds for coal road repair and maintenance appear in the form of a five percent sales tax in the coal producing counties. Deposition of tax receipts have been made in general and county funds according to an 80/20 percent funding distribution.

4.3 Port Facilities for Exporting Illinois Coal

The increased world demand for steam coal has resulted in a strain on U.S. coal exporting facilities. Illinois′ position in the world steam coal market is severely restricted by inadequate port facilities. The constraints imposed by these coal handling facilities is further emphasized as other leading coal exporting nations update their port facilities. Major competitors of the United States are improving shipping/loading facilities as the composition of the world coal fleet continues to be upgraded through the replacement of the common 50 to 75 thousand dwt vessels with ore/bulk carrier

vessels in the size range of 100 to 150 thousand dwt. The former vessels are often referred to by the term Panamax, as they are the largest ships that can be accomodated by the Panama Canal.

For Illinois to become a leading competitor in the world steam coal trade, improvements to the national port system is a crucial factor. The capability of the national port system to link inland transportation and the world market is essential for trade development and economic stability. To facilitate increasing volumes of coal with the expansion of the world steam coal market, the national port system will have to supply the capacity to provide for extensive growth in waterborne commerce.

One of the major reasons that coal loading facilities at ports have become a severe constraint on coal movement is that they had previoulsy been designed for exporting metallurgical coal. As a result, coal handling ports are not adequately equipped to service the expansion of the United States' steam coal exports without major improvements to the facilities as well as to the ports themselves.

Metallurgical coal is traded in various ranks and grades. For this reason, it must be stored in the hopper cars by which the coal was transported. This procedure can result in substantial loading delays. In contrast, steam coal can be stored on the ground and moved by bulk loading methods. Because existing facilities were designed for the movement of metallurgical coal, ground storage is generally not available. As a result, the steam coal must also be stored in hopper cars, which tends to increase loading and shipping delays. The resulting demurrage charges of $15,000 to $20,000 per ship per day add $7 to $10 per ton to the cost of coal shipments.

This fundamental difference in handling steam coal over metallurgical coal is compounded by problems unique to each coast. The Atlantic Coast has

no ground storage and inadequate bulk material handling facilities that are not readily adaptable for steam coal trade. The Gulf Coast has adequate ground storage capacity, but had inadequate barge and rail connecting facilities in the past. Both the Gulf Coast and the Atlantic Coast share the problem of minimal port depth. The Pacific Coast, although it does not have port depth constraints, faces the need for costly additions to both rail links and port facilities before it can adequately handle and unload coal unit trains.

Several coal handling facilities were built at Atlantic Coast ports in the 1950′s to serve the metallurgical coal market. These terminals are owned and operated by railroad companies which are obligated as common carriers to serve customers that demand service. Most coal export facilities consist of a large rail yard with rail car dumpers which are connected by conveyor belts to travelling ship loaders. Since blending of metallurgical coal must be accurately controlled to obtain the specified carbon content and chemical structure for making coke, several rail cars of coal are blended as they are dumped into the ship. This coal blending process often is the major reason for shipping delays.

Blending is not as accurately controlled for steam coal. New terminals for handling steam coal are different in two major ways:

1. Terminals are generally owned and operated by private firms.
2. Large rail yards are being replaced by large, open stockpiles.

Unlike the rail owned terminals that were obligated to service all grades of coal, privately owned terminals can control the number of grades of coal entering their terminal, permitting the use of stockpiles instead of hopper cars for storage. These stockpiles are usually segregated into a minimal

number of coal grades. Unlike metallurgical coal, however, steam coal is traded on the basis of its heating ability (calorific value expressed in Btu/lb) and its sulfur and ash content. Therefore, stockpiles and conveyor belts to remove coal from stockpiles can be used. The combination of belts and ground storage allows continuous loading of coal which reduces ship loading delays.

Currently, several existing coal terminals are being expanded to handle the increase in steam coal trade. Even more coal export facilities are being reopened or planned. The major coal handling facilities on the Atlantic Coast are the Ports of Philadelphia, Baltimore, and Hampton Roads (Norfolk and Newport News). The Ports of Mobile and New Orleans currently service the Gulf Coast. The Pacific Coast handles only small quantities of coal at the Ports of Long Beach and Los Angeles. These terminals are described in more detail in the next three sections, followed by a description of worldwide loading and receiving terminals.

4.3.1 The Atlantic Coast

Port of Hampton Roads Over 75 percent of U.S. coal is exported to foreign ports (except Canada) through the Port of Hampton Roads. Hampton Roads exported 37 million tons of coal in 1979 and 57 million tons in 1980. Hampton Roads is serviced by two major coal terminals: the Norfolk and Western Railroad's facilities at Lamberts Point and the Chesapeake and Ohio Railroad's piers at Newport News, as shown in Table 4.3.

Lamberts Point Coal Pier No. 5 and 6 are the termini for over 200 coal producers on the Norfolk and Western rail system. Pier 5, the smaller of the two facilities, has one fixed electric car dumper which services one ship at a

Table 4.3

Capacity for Handling Export Coal: Atlantic Coast

	Vessel Size (10^3 DWT)		Existing Capacity (10^5 tons/yr)		Capacity Expansion (10^5 tons/yr)		Total Mid to Long Term Capacity 1985 (10^5 tons/yr)
	Existing	Proposed	Designed	Effective	Planned	Underway	
New York (P)	80		5.0	2.5	5.0		5
Philadelphia	60					6.5	9
Pier 124 (E)							
Canton (P)	35				2.0		4
Wilmington (P)	30				7.5		7
Lower Delaware Bay (P)	100				10.0		10
Baltimore (E)	70	100	27.2	16.6	11.0	6.5	34
Norfolk							
Pier 6-North (E)	80	100	58.0	29.0	7.3		36
Pier 6-South (E)			8.0	4.0	1.0		5
Newport News							
Pier 14 (E)	80	100	33.0	16.5			16
Pier 15 (E)			14.0	5.3		5.0	10
Pier 9 (E)					5.0		5
Portsmouth (P)	50	100			10.0		10
Morehead City (P)	50	100			5.0		5
Charleston (P)	40	50			5.0		5
Savannah (P)	50	70			7.5		7
Brunswick (P)	30	43			5.0		5
Total Atlantic Coast			145.2	73.9	81.3	19.0	173

P: Planned
E: Existing

Source: U.S. Department of Energy. [20].

time with the handling capacity of fifty 70-ton cars of coal per hour for a maximum capacity of 2,520 tons per hour. Due to its restrictive draft (39 feet high tide and 36 feet low tide) Pier 5 is used with less frequency than Pier 6, which handles the bulk of the vessels at Lamberts Point. Pier 6 is said to be the world's largest and fastest coal loading facility, and can load more classes of ships with its less restrictive draft of 46.5 feet. It has a maximum loading capacity of 20,000 net tons per hour and an average loading capacity of 16,000 net tons per hour. Pier 6 has two traveling ship loaders that can load two ships at a time. It also has facilities to thaw coal so that it can operate on a year round basis.

Newport News, Virginia, is the location of the Chesapeake and Ohio Railway Company Pier No. 14 and No. 15. Pier No. 15, reopened in August of 1981 in response to the increase in world demand for steam coal, has an average loading capacity of 3,000 tons per hour. Pier 15 has a 38-foot draft that restricts the amount of bulk cargo that can be loaded on the vessel. Ships that are too wide-beamed for Pier 15 are loaded at Pier 14 which has a draft of 45 feet and an average loading capacity of 8,000 net tons per hour. Two ships may be loaded simultaneously at Pier 14, and a thawing system insures year round loading and reduces waiting time.

Several improvements have been proposed for increasing the total coal handling capacity of Hampton Roads. A. J. Massey Coal Company has plans to renovate Pier 9 at Newport News. Sixty acres of land adjacent to the pier will be purchased for ground storage with a capacity of 1.4 million tons of coal. Another proposal by Cox Enterprises and several other large coal companies includes plans for a 18.2 tons per year capacity facility. Four other coal producing firms have invested in 72 acres of land between C and O's

Pier 14 and Massey's Pier 9. These proposals are in an early stage of development.

Port of Philadelphia Conrail's Pier 124, located on Greenwich Point on the Delaware River, is the Port of Philadelphia's most active coal terminal. Serviced by a 40-foot channel, the port is currently undergoing development to accommodate double vessel loading. At the end of the Phase I development, Pier 124 had reached a capacity of 3.3 million tons per year and a handling capacity that will allow the loading of 40,000 dwt vessels. Future phases will bring the capacity to 11 million tons per year with facilities to accommodate 80,000 dwt vessels. Conrail is also in the process of developing and renovating 230 miles of rail trackage between its Clearfield, PA, coal yards and Philadelphia.

Port of Baltimore Baltimore and Ohio's Curtis Bay Coal Pier owns and operates two of the three coal facilities. These piers have the capacity for loading one vessel and five barges simultaneously. Its maximum capacity for loading is 6,000 tons per hour for vessels and 4,000 tons per hour for barges. The draft is 40 feet mean tide, and the pier can handle vessels up to 60,000 dwt. The B & O is trying to reduce vessel waiting time by sending coal by barge to vessels waiting at its Port Covington ore pier in Curtis Bay.

Several proposals have been developed to expand the Port of Baltimore coal handling facilities. Island Creek Coal Company plans to develop a 25-acre coal stockyard adjacent to the existing coal pier with a planned storage capacity of 300,000 to 500,000 tons. Consolidation Coal Company plans to buy the old Canton Marine Terminal and develop a facility that will load 11 million tons per year with storage capacity of 750,000 tons, and service 175 to 200 vessels per year. Marley Neck, North of Curtis Bay, is also being

considered for development. The 500-acre tract will be converted to a 15 million ton per year capacity facility.

4.3.2 The Gulf Coast

As a result of the growing problems on the Atlantic Coast, several foreign coal buyers have turned a cautious eye towards the Gulf Coast. Two major coal exporting terminals, the Port of New Orleans and the Port of Mobile, as well as several developing ports at Baton Rouge, Louisiana, and Galveston, Texas, are making major improvements to handle the increase of steam coal movements as shown in Table 4.4.

Port of New Orleans. The Port of New Orleans is particularly attractive to shipment of coal from Midwestern mines. Currently, New Orleans is the second largest U.S. port in terms of total waterborne tonnage, and the largest grain port in the world. Coal shipments were 1.4 million tons per year in 1979, and 3.3 million tons in 1980. The Port of New Orleans has convenient barge and rail unloading faciltities. It also does not have problems with seasonal freezing, thus ensuring year round operations with no impairment to barge traffic. For this reason and others, the American Barge Line and the Federal Barge Line are constructing a $55 million transfer facility with an estimated capacity of 30 million tons annually.

The Port of New Orleans currently is serviced by three terminals: Electro-Coal Transfer Terminal, International Marine Terminals, and the Public Bulk Terminal. Eight other coal facilities are either under design or planned, as shown in Table 4.5. Electro-Coal Transfer Terminals, owned by the Tampa Power Company, is located at mile 55 in Davant. Currently, Electro-Coal is involved in a two-phase expansion program. At the end of Phase I,

Table 4.4

Capacity for Handling Export Coal: Gulf Coast

	Vessel Size (10^3 DWT)		Existing Capacity (10^5 tons/yr)		Capacity Expansion (10^5 tons/yr)		Total Mid to Long Term Capacity 1985 (10^5 tons/yr)
	Existing	Proposed	Designed	Effective	Planned	Underway	
Mobile (E)	60	100	11.0	5.5		5.0	10.5
New Orleans-Davant (E)	60	100	14.0	7.0	3.0		10.0
Myrtle Grove (E)	60	100	6.0	3.0	9.0		12.0
Mile 118 (P)	60	100			4.0		4.0
Baton Rouge (Burnside) (E)	60	100	5.0	2.0	4.0		6.0
Port Arthur (P)	60	100			2.0		2.0
Galveston (P)	55	100			10.0		10.0
Corpus Christi (P)	75	100	—	—	0.5	—	0.5
Total Gulf Coast			36.0	17.5	81.5	5.0	55.0

E: Existing
P: Planned

Source: U.S. Department of Energy [20].

Table 4.5

Existing and Planned New Coal Terminals for the Mississippi River Baton Rouge to the Gulf and the Mississippi River-Gulf Outlet

Name & Location	1983 Capacity (10^5 tons)	1990 Capacity (10^5 tons)
Electro-Coal Transfer Terminals, Mile 55 Above Head of Passes (AHP) Existing	12	30
International Marine Terminals, Mile 57 AHP Existing	12	25
Ryan-Walsh Stevedoring Bulk Terminal (MR-GO) Existing	4	4
Freeport Coal Terminal Co. Port Sulphur, Mile 39.2 AHP, Under Design	4	8
International Matex Tank Terminals Mile 46.6 AHP (West Bank) Under Design	12	15
NOLA Coal Loading Facility, Inc., Mile 47 AHP (East Bank) Under Design	2	3
Citrus Lands, Inc., Mile 54 AHP Planned	6	6
Gateway Terminals, Inc., Mile 162 AHP (East Bank) Under Design	6	10
Miller Coal Systems, Inc., Terminal, Mile 174 AHP Under Design	10	20
River and Gulf Transportation Co., St. Gabriel, Iberville, Mile 213 AHP Under Design	12	15
French Government Facility, Location Not Specified Planned	5	10
Sub Totals	85	146
Mid-Stream Capability	24	24
Totals	109	170

Source: Coal Facility Fact Sheets [2].

Electro-Coal will have the storage capacity of two million tons and a traveling ship loader that will bring total operating capacity to 12 million tons. This increased efficiency will reduce total loading time by approximately 6.5 hours for a Panamax vessel. Due to the longer and higher reach of the loader, the facility will be able to handle 5,000 tons per hour. Phase II, to be completed in mid-1983, will realize a storage capacity of 12 million tons and an operating capacity of 25-30 million tons. These improvements, however, will not affect the type of vessels Electro-Coal will service. Due to their limiting draft, Electro-Coal only receives coal from barges and directly transfers the coal to ocean going vessels of Panamax size.

The Federal Barge and American Barge Lines jointly own the International Marine Terminals (IMT) at mile 57 AHP in Myrtle Grove. This facility has a 7,000 ton per hour direct transfer capacity and a 4,000 ton per hour reclaim from storage capacity. Coal is received at the terminal and transferred from barges to shore at the rate of 1,500 net tons per hour. IMT is designed so that as coal tonnage increases, a traveling high speed ship loader and a bucket wheel stacker reclaimer can be added without interruption of operations. Throughput capacity is 12 million tons per year and should be more than double this figure by 1990. IMT also has the facilities for adequately blending coal if the necessary level of sulfur content is to be met in this manner. IMT has a 55-foot draft and services mostly 30,000 dwt vessels with future plans to service up to 150,000 dwt vessels.

The Public Bulk Terminals, currently owned by the Board of Commissioners for the Port of New Orleans and leased to Ryan-Walsh Stevedoring, has a direct loading capacity of 1,200 tons per hour and receives barges almost exclusively. It has 80,000 tons of open storage capacity and handles approximately four million tons of coal per year. Eight other coal terminals

are being designed or planned. The Port of New Orleans also has intentions of servicing larger vessels in the 140,000 to 200,000 dwt range.

Currently, most of the Mississippi River has a 55-foot draft; a restriction exists, however, at a relatively short stretch of river between Head of Passes, Venice, Louisiana and Southwest Passes. Fifteen areas with severe cross currents also have resrictive drafts. The U.S. Army Corps of Engineers (CoE) is currently considering dredging this area and constructing a turning basin 1,600 feet wide by 4,000 feet long and 55 feet deep at Baton Rouge. Even without considering the recent surge in demand for high sulfur coal, this project was evaluated to have a benefit cost ratio of 8.5 to 1 [17].

Port of Mobile The Port of Mobile is considered one of the most modern coal handling facilities in the world. McDuffies Terminals' bulk coal export plant is equipped with the latest facilities for handling coal. Thirty-two barges can be accommodated in the staging area and the barge unloader can handle up to 3,000 tons per hour. Rail shipments can also be handled and unloaded by a rotary car dumper at the rate of 30 cars an hour. Coal can be transported directly to the ship loader or deposited onto storage pads. A high capacity rail-mounted stacker reclaimer can handle up to 4,000 tons per hour. The loading berth can handle bulk carriers up to 850 feet long with 40 foot drafts. In 24 hours, a waiting vessel of 52,000 dwt can be loaded.

Currently, McDuffie Terminals is undergoing a a multiphase expansion program. The Phase II expansion resulted in a capacity of 6.5 to 7 million tons. Phase III will include a new dock, shiploaders, and a third reclaimer to reach a throughput capacity of 25 million tons. Presently, McDuffie Terminals is serviced primarily by four railroads: Burlington Northern, Southern, Family Lines, and ICG. The completion of the Tennessee-Tombigbee

Waterway in 1985 will connect the Port of Mobile to coal producing regions in Central Appalachia and Illinois.

4.3.3 The Pacific Coast

The existing and potential capacity for handling export coal on the Pacific Coast is shown in Table 4.6. Currently, the deepest channels in the U.S. are found on the Pacific coast. Los Angeles has a draft of 52 feet and can accommodate partially loaded vessels as large as 120,000 dwt. Although Long Beach also has a depth of 52 feet, port handling and existing inland rail facilities restrict steam coal shipments. Currently, Long Beach is undergoing a major expansion that will allow the port to handle in excess of 30 million tons per year by 1990. This expansion will make Long Beach the largest coal facility on the Pacific Coast.

4.3.4 International Loading and Receiving Ports

The world port facilities--both loading and receiving--will ultimately determine the future range of vessel sizes. Several foreign terminals already have the capacity to handle coal carrying vessels in the 100,000 to 150,000 dwt range. The major coal-loading facilities for the 100,000 dwt and vessels are located in Australia, South Africa, Western Canada, Western Europe and Japan. Due to the steady increases in port capacities and the increased use of vessels of 100,000 dwt, the utilization of such coal carriers is expected to increase from 21 percent to 36 percent by 1990 and 43 percent by 2000.

In planning for the U.S. port system, and its role in increased coal movement, the system's compatibility with world loading terminals must be

Table 4.6

Capacity for Handling Export Coal: Pacific Coast

Ports/Terminal	Vessel Size (10^3 DWT) Existing	Vessel Size (10^3 DWT) Proposed	Existing Capacity (10^5 tons/yr) Designed	Existing Capacity (10^5 tons/yr) Effective	Capacity Expansion (10^5 tons/yr) Planned	Capacity Expansion (10^5 tons/yr) Underway	Total Mid to Long Term Capacity 1985 (10^5 tons/yr)
Los Angeles (E)	100		4.0	1.5	7.5		9.0
Long Beach (E)	100		4.0	1.5	5.0		6.5
Sacramento (P)	30	40			1.2		1.2
Stockton (P)	35	40			1.2		1.2
Astoria (P)	50				5.0		5.0
Portland (P)	55				3.0		3.0
Coos Bay (P)	35				3.0		3.0
Kalama (P)	50				7.5		7.5
Bellingham (Cherry Point) (P)	100				1.2		1.2
Dupont, Washington (P)	100				3.0		3.0
Grays Harbor (P)	40	60			3.0		3.0
Anchorage (P)	100				3.0		3.0
Trading Bay (P)	100				3.0		3.0
Total West Coast			8.0	3.0	46.6		49.6

P: Planned
E: Existing

Source: U.S. Department of Energy [20].

considered. Table 4.7 summarizes the information available on international coal loading terminals with the capability to accommodate vessels over 60,000 dwt. The existing coal loading terminals throughout the world are dominated by five major facilities. Three of the relatively newer facilities are Roberts Bank (Canada), Richards Bay (South Africa) and Hay Point (Queensland). The two older terminals are at Hampton Roads, i.e., the Chesapeake and Ohio facilities at Newsport News and the Norfolk and Western facility at Lambert Point. As noted previously, these older terminals handle approximately 75 percent of the U.S. coal exports to non-North American destinations. However, Hampton Roads, like most of the other coal loading facilities throughout the world, was designed to load fully Panamax vessels; in contrast, the newer terminals can accommodate and fully load vessels of more than 150,000 dwt.

The United States has to overcome restrictions in minimal harbor and channel depths, as well as the limitations inherent in the Panama Canal. Therefore, even though the U.S. has the greatest number of coal loading terminals, most are restricted to handling Panamax vessels. Currently, only Hampton Roads can fully load an 80,000 dwt vessel. Vessels in excess of this size can only be partially loaded at Hampton Roads. Combined carriers can then load other cargo such as iron ore at foreign terminals en route to final destinations. The procedure of partially loading vessels will necessarily increase as the size of coal carrying vessels increases to around 120,000 dwt and foreign ports increasingly accommodate larger vessels. The Panamax vessels will eventually be used for smaller shipments and short haul movements of steam coal. Potential solutions to this major bottleneck are development of less restrictive channel drafts by dredging or construction of off-shore loading terminals.

Table 4.7

World Coal Loading Facilities for Vessels of 60,000 dwt and Over

Country	Port	Facility	Nominal Annual Capacity (Million tons per annum)	Maximum Vessel Size	Maximum Draft	Nominal Loading Rate	Remarks
Argentina	Punta Loyala	Y.C.F.	NA	110	52.5	2	Planned transfer terminal
Australia	Newcastle	Carrington Basin Steelworks Channel	16.0	55	39.4	2	Expansion to 25 million ton per annum commencing in 1982. Maximum vessel size will be increased to 65 dwt (draft 13 meters) at Carrington Basin and 110 dwt (draft 15.1m) at Steelworks Channel. Loading capacity at Steelworks Channel loader being increased to 7.5 t.p.h.
		Kooragang Island	15.0	110	49.5	8	New facility commencing in 1984 - Ultimate capacity 5 million tons per annum.
	Port Kembla	Government Loader	7.5	60	41.7	2.5	New facility replacing existing facility commencing 1982. Loading rate will increase 5 ton per hour and vessel size up to 110 dwt. Nominal capacity of 14 million tons per annum.
	Hay Point	No. 1 Berth	20.0	160	55.1	approx 4	
		No. 2 Berth		160	55.1	approx 6	
		Hay Point North	10.0	160	55.1	approx 6	New facility commencing in 1983. Provision for expansion (2nd berth) deepening to accommodate 200 dwt vessels.
	Gladstone	Auckland Point No. 1 Berth	-	-	-	1.6	Gladstone Harbour Board
		Barney Point	-	65	-	2	Thiess-Dampier-Mitsui
		Clinton	-	65	-	4	Stockpile to be expanded, commencing 1981. Channel to be deepened to 15 meters to allow vessels of 120,000 dwt.

Country	Port	Facility	Nominal Annual Capacity (Million tons per annum	Maximum Vessel Size	Maximum Draft	Nominal Loading Rate	Remarks
Canada	Vancouver	Roberts Bank (Westshore)	10.0	150	65.6	7.7	Expansion to 25 million tons per annum commencing 1983 with increased draft, vessel size and loading rate.
		Neptune Coal Terminal	6.0	120	55.1	4	The nominal capacity will be increased to 7.5 million tons per annum. Timing not known.
		Pacific Coast Bulk Terminal (Port Moody)	1.5	65	42.7	2	
	Prince Rupert	-	9.0 (minimum)	150	55.8	NA	New terminal commencing 1983.
China	Lien Yun Kung	-	NA	NA	NA	NA	Planned development for coal export--mid 1980's.
	Chin Wang Tao	-	NA	NA	NA	NA	Coal Dock under construction.
India	Haldia (Calcutta)	Export Berth	NA	60	41.0	3	
Poland	Gdansk	North Port Coal Terminal	NA	100	48.9	4	
	Swinoujascie	S.P.A. Miners Quay	NA	60	41.3	2	
South Africa	Richards Bay	Coal Terminal	24	165	56.1	6.5	Capacity is planned to reach 44 million tons by 1985 allowing vessels of 250 dwt on 23 meter draft.
United States	Baltimore	Chessie System Curtis Bay Berths	NA	65	42.0	3	Two berths

Country	Port	Facility	Nominal Annual Capacity (Million tons per annum)	Maximum Vessel Size	Maximum Draft	Nominal Loading Rate	Remarks
United States	Baltimore	WMRR Port Covington Pier	NA	60	40.0	3.5	Two berths
	Galveston	Bulk Terminal Berth	5	150	55.1	6	Two berths planned with capacity of 5 million tons by 1985.
		Soros Associates Terminal	NA	75	45.0	NA	Planned export terminal
	Hampton Roads	N&W Railroad Lamberts Pt. Piers No. 5 and 6	25	80	45.0	16 (total)	Capacity of 8,000 tph at each pier.
		Chessie System Piers No. 14 and 15	32	75	44.0	9 (total)	
	Mobile	ASD McDuffie Terminals	NA	75	44.0	3.5	Channel and berth dredging to 15.2 m.
	Burnside	Transfer Terminal	NA	60	40.0	1.5	
	Long Beach	San Pedro	5	75	-	-	14 mtpa capacity planned.
Union of Soviet Socialist Republics	Vostochny (Pacific)	Coal Export Berths	2	100	48.0	8	Planned capacity 10 mtpa. Four berths.

Source: Coal Resources Development Committee [3].

The capabilities of world receiving facilities of coal importing nations will also have a large impact on the needs of the U.S. port system. The size of vessel that these facilities can accommodate will be a major factor in determining the range of vessel size for which coal loading terminals must be designed. Table 4.8 shows facilities being planned and constructed, and their projected capabilities. Large metallurgical coal receiving facilities are associated with the steel industry in Japan and Europe. More recently, major terminals are being constructed at Rotterdam and Fos-de-Mer (Marseille). Most of the remaining receiving terminals were built to accommodate Panamax size vessels, indicating the development of a few major regional terminals that will be used as discharge and transshipment centers. Recently, terminals are being designed or reconstructed for receiving larger vessels. Because of the cost of developing terminals that will accommodate larger bulk carriers, it appears that only a few larger bulk terminals will be develeped in central locations. In this way, economies of the use of large vessels for long-haul sea routes can be realized while transshipment to smaller vessels can be used in smaller ports.

4.4 Factors Affecting Oceanborne Transportation Costs

Since 1978 the world coal carrying fleet has undergone remarkable transformations in total size, capacity, character and overall organization. The combination of these factors have affected both the cost and draft requirements of transporting coal. For the most part, world coal shipments are carried in bulk carriers and combination vessels. Bulk carriers carry dry bulk cargo such as coal, whereas combination vessels, or ore-bulk-oil (OBO), are capable of carrying cargos in liquid form as well as dry bulk cargos.

Table 4.8

World Coal Receiving Facilities for Vessels of 60,000 dwt and Over

Country	Port	Facility	Maximum Draft (feet)	Maximum Vessel Size (10^3 dwt)	Remarks
Algeria	Annaba	-	-	-	Planned improvement 1983-85
Belgium	Antwerp	Stocatra, Hansa Dock	44.0	120	Four berths
	Antwerp*	Canal Dock B*	44.0	120	Planned 1983. Future draft 16 meters
	Zeebrugge*	Coal Import Berth*	NA	120-150	Planned for post 1985
Brazil	Sepetiba	Steelworks Berth	54.1	150	-
Denmark	Enstedvaerket (Aabenraa)	Elsam Coal Berth	49.2	150	Planned draft 17 meters
	Stignaesvaerket	-	49.2	120	-
	Aarhus*	-	42.7	120	Planned 1983
	Asnaesvaerket	-	36.1	70	Planned draft 12.5 meters
France	Marseilles	Coal Berth	49.2	120	Planned draft 16.8 meters in 1981, 21.5 meters in 1981+
	Dunkirk	Solmer Ore Quay	63.9	180	Steelworks wharf
		PAD Appontement	46.6	100	Coal and ore wharf
		Usinor Berth No. 5	44.0	75	Steelworks wharf
		West Harbour (Quay Paul Reynaud)	59.1	185	18.5m to be completed 1982. Planned deepening to 22m for 250
	Le Havre	Coal and Ore Berth	54.1	150	Accommodation for 180 dwt planned
Greece	Makronisos*	-	NA	120	Planned 1984
Hong Kong	-	Castle Peak Power Station*	NA	120	Under construction
	-	China Cement Co.	NA	60	Proposed
		Hong Kong Electric*	NA	100	Under construction
Italy	Taranto	Italsider Berth 1	51.0	100	Steelworks wharf
		Italsider Berth 2	75.5	250	Steelworks wharf
	Trieste	Italsider Berths	45.0	80	Steelworks wharf
	Trieste*	-	55.8	150	Planned 1984, new terminal
	La Spezia	-	42.0	80	-

Country	Port	Facility	Maximum Draft (feet)	Maximum Vessel Size (10^3 dwt)	Remarks
Italy	Porto Vesme	-	39.4	90	-
	Genoa	-	NA	80	-
	Naples (Bagnoli)	-	NA	80	-
	Piambino	P.D.P. Acciaiere	NA	80	-
Japan	Hirohata	No. 18 Wharf	54.1	160	Nippon Steel
	Hirohata	-	44.3	110	Nippon Steel
	Kamaishi	No. 3 Pier South	44.3	120	Nippon Electric
	Matsushima	-	45.9	69	Electric Power Development
	Muroran	Wharves 18/19	52.5	160	Nippon Steel
	Kimitsu	Wharves 21/22	55.8	160	Nippon Steel
	Tobata	-	52.5	160	Nippon Steel
	Nagoya	Berths F12/13	45.9	100	Nippon Steel
	Oita	Nippon Steel Terminal	78.7	300	Nippon Steel
	Sakai	Wharves 3A/B	44.3	160	Nippon Steel
	Sakai	Osaka Gas	45.9	80	Osaka Gas
	Fukuyama	Ore/Coal Berths ABC	52.5	200	Nippon Kokan
	Keihin	Ohgishima Terminal	55.8	200	Nippon Kokan
	Chiba	Kawasaki Steel Terminal	55.8	160	Kawasaki Steel
	Mizushima	Berth E	52.5	160	Kawasaki Steel
	Kakogawa	Piers 3 and 4	52.5	160	Kobe Steel
	Kobe	-	41.0	65	Kobe Steel
	Kure	Berth 2/3	55.8	150	Nissin Steel
	Kashima	Berth B	56.8	180	Sumitomo Metals
	Wakayama	Berth C	45.9	165	Sumitomo Metals
	Kokura	-	34.1	130	Sumitomo Metals
	Tomato*	Coal Center sponsored by Electric Power Industries	NA	60 (stage 1)	First stage commissioning 1983 for 3.5 million tons per annum
				100 (stage 2)	Second stage commissioning 1983 for 8.5 million tons per annum
	Sakito*	Coal Center sponsored by Electric Power Industries	NA	150	First stage commissioning 1988 for 7 million tons per annum. Second stage commissioning 1993 for 10 million tons per annum. Plans in 1982 for 1.5 million tons per annum.
	Hibikanada*	Coal Center	NA	60	Planned 1982 for 1.5 million tons per annum.

Country	Port	Facility	Maximum Draft (feet)	Maximum Vessel Size (10^3 dwt)	Remarks
Japan	Sukume*	Coal Center	-	60-130	Commissioning date not yet decided. For 10 million tons per annum
Netherlands	Amsterdam	O.B.A. Westhaven	44.9	120	Transhipment Terminal
	Ijumuiden	Hoogovens Outer Harbour No. 2	44.9	80	
	Rotterdam	Swarttouw, St. Laurenshaven	62.7	90	3 berth transshipment terminal
	Rotterdam	Maasvlakte EKOM	65.0	250	Planned water depth 22.65 meters (1983)
	-	Maasvlakte MCT*	58.4	250	Planned 1982. Planned water depth 22.65 meters
	Delfzijl	P.S.A. Eemshaven	74.8	65	Dredging of berths 13.7 planned
Pakistan	Port Qasim	PSMC Raw Materials Berth	44.3	75	Planned
Phillipines	Sangi	-	NA	60-70	Under construction
	Nonoc Island	-	NA	80	Under construction
Portugal	Sines	-	NA	60	Planned 1997, later for 120, 150 dwt
Spain	Bilboa	J.P.B. Adosada Bulk Berth	44.0	75	Steelworks wharf
	Gijon-Musel	J.B.G. Dique North Pier 1	45.9	100	Possible development for 150-200 dwt vessels
	Taragona	-	42.0	60	Later to 70 dwt
	Algeciras*	-	NA	100+	Planned 1985
	Carboneras*	-	55.8	150	Planned 1985
South Korea	Pohang	-	-	100	-
	Samcheonpo*	-		100	Planned 1982
	Gojeong*	-		100	Planned 1983
Sweden	Lulea	-	42.0	60	
	Gothenburg*	-	59.1	200	Planned, includes transshipment facilities 1987-88
	Oxelsund*	-	43.0	70	Planned draft 15 meters
Taiwan	Kaohsiung	-	45.9	125	
	Ta-Lin*	-	NA	120	Planned 1983
	Taichung*	-	NA	65	Planned 1981
	Shen-Ao*	-	NA	60	Planned 1983+
	Su-AC*	-	NA	130	Planned 1984

Country	Port	Facility	Maximum Draft (feet)	Maximum Vessel Size (10^3 dwt)	Remarks
Turkey	Iskenderun	-	37.1	40	Planned for 120 dwt 1983-85 with 16 meter draft
United Kingdom	Hunterston	B.S.C. Ore/Coal Terminal	56.1	150	Steelworks wharf
	Middlesborough	Redcar Terminal	-	150	Steelworks wharf
	Port Talbot	Ore Terminal	49.2	100	Imports for Steelworks
United States	Galveston*	-	39.4	60	Planned. Draft possibly to 15m accommodating 110 dwt vessels.
West Germany	Hamburg	Wedal Coal Terminal	42.7	70	
		Hansaport. Bulk Terminal	44.3	120	
	Nordenham	Midgard Pier 1	42.0	65	
	Wilhelmshaven	Niedersachsen Bulk Berth	45.9	90	
	Bremerhaven	-	NA	70	
	Emden	Emden Hafen Berth	NA	60	
Yugoslavia	Rijeka (Bakar)	Bakar Basin Bulk Berth	49.2	115	Berth being deepened for 120 dwt for 1983-85 16 meter drafts

* Indicates planned new facilities or under construction

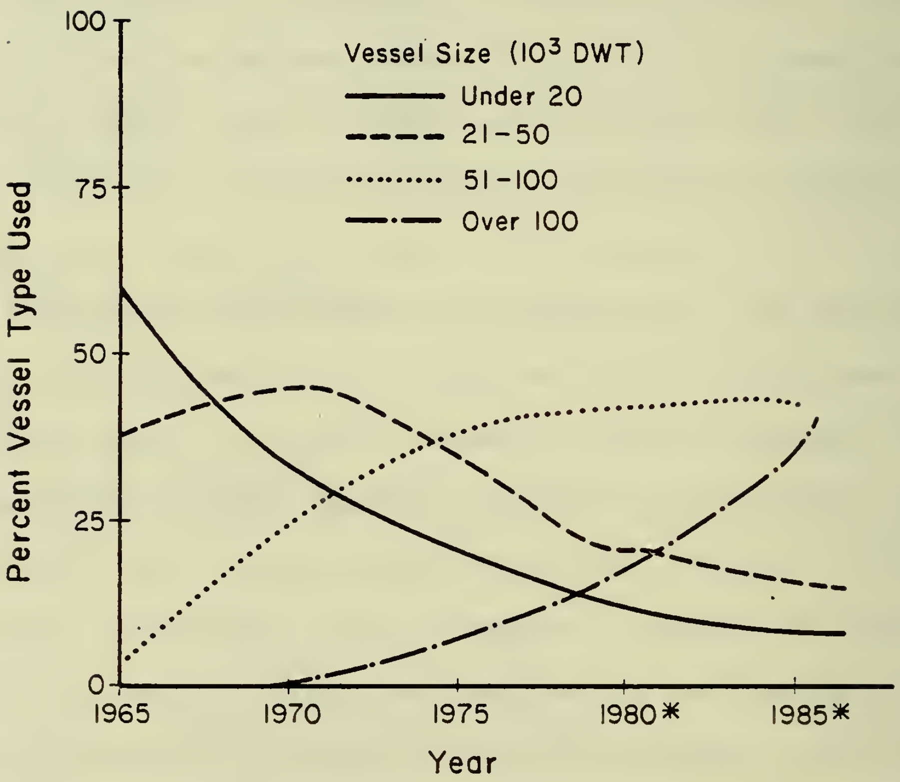
Source: Coal Resources Development Committee [3].

During the past two decades, the use of bulk and combined carriers has increased significantly. Dry-bulk carriers alone have expanded from carrying 10 million dwt in 1962 to over 150 million dwt in 1978. Fearnly and Egers Chartering Co. Ltd. reported in 1980 that bulk carriers alone accounted for more than one-half the world order book, reaching an all time high of 17.2 million dwt. The smaller vessels of 15,000 dwt or less have been displaced by the larger vessels of the dry bulk carriers and OBO as shown in Figure 4.3. From 1965 to 1980, the use of 20,000 dwt (or less) vessels in the world coal carrying fleet has declined from almost 60 percent to 18 percent of the total tonnage of coal carried; at the same time, vessels over 100,000 dwt have increased from zero to 21 percent [7]. These figures portend the beginning of massive construction of bulk carriers for the future transport of coal.

This increase is further evidenced in Table 4.9, which shows the number and size distribution of general purpose and combined carriers on order from 1978 to 1981. Clearly, there has been some decrease in the numbers and size distribution of combined carriers of over 100,000 dwt. At the same time, however, there has been a significant increase in the orders for large general purpose carriers, particularly in the Panamax and 100-150,000 dwt size ranges. It is also clear that a greater percent of the latter, especially in the 125,000 to 150,000 dwt size range will be built for coal transport. The increased use of larger vessels in turn required greater draft, as shown in Table 4.10. The size of future vessels to be used for international coal transport, therefore, is an important factor in determining port development.

Figure 4.3

Coal Trade Carried by Size of Vessel



* Projected
Source: Peabody Coal Co. [14].

Table 4.9

Ordered Vessels Suitable for Coal Transport

Vessel Size Range (DWT)	Combined Carriers: Ordered at 1/1978 Number	Combined Carriers: Ordered at 1/1978 Total Tonage (10^3 DWT)	Combined Carriers: Ordered at 1/1981 Number	Combined Carriers: Ordered at 1/1981 Total Tonage (10^3 DWT)	General Purpose Bulk Carriers: Ordered at 1/1978 Number	General Purpose Bulk Carriers: Ordered at 1/1978 Total Tonage (10^3 DWT)	General Purpose Bulk Carriers: Ordered at 1/1981 Number	General Purpose Bulk Carriers: Ordered at 1/1981 Total Tonage (10^3 DWT)
10,001-25,000	–	–	–	–	–	–	43	958
					314	8,015		
25,001-40,000	–	–	4	220			165	5,326
40,001-60,000	–	–	–	–	41	1,897	67	3,442
60,001-80,000	–	–	15	1,127	–	–	100	6,516
	9	631	–	–	30	2,079	–	–
80,001-100,000	–	–	4	322	–	–	6	507
100,001-150,000	19	2,276	8	930	13	1,505	61	7,867
150,001-200,000	1	168	3	470	NIL	NIL	7	1,334

Source: Coal Resources Development Committee [3].

Table 4.10

Relationship of Vessel Size to Coal Carrying Capacity

10^3 DWT* (thousands of tons)	Overall Length	Beam	Draft
40	630'	105'	35'
60	760'	105'	40'
100	910'	116'	48'
150	980'	133'	56'
200	1020'	150'	62'

* Vessels fully loaded and fueled.

Source: U.S. Maritime Administration [21].

Table 4.11

Characteristics of Lash and Seabee Barges

Dimensions	Lash	Seabee
Overall		
Length	61' 6"	97' 6"
Beam	31' 2"	35' 0"
Depth	12' 0"	12' 6"
Draft	8' 6"	
Internal		
Length	59' 9"	90' 0"
Width	29' 5"	30' 3"
Depth of Hold	10' 2"	14' 6"
Capacities	19,900 cu. ft. 407 tons	39,140 cu. ft. 913 tons

Source: U.S. Maritime Administration [10].

4.5 Short-Term Solutions to Reducing Oceanborne Transportation Costs From the Gulf Coast

Oceanborne transportation costs are a large factor in determining whether Illinois coal will be competitive in the world steam coal market. Restrictions such as the Panama Canal and drafts less than 50 feet limit the use of the larger bulk carriers for coal shipments. With the immediate possibility of foreign competitors utilizing larger vessels, it is essential to analyze some short-term alternatives for reducing the total unit cost of shipping Illinois coal. These short-term solutions can help reduce marine freight rates and accomodate larger vessels in the world coal transport fleet. With the anticipated significant increase in coal exports, combined with vessel size increases and longer sea routes, short-term solutions will not preclude the need for expansion of the national port system.

4.5.1 Offshore Deep Water Loading and Midstream Operations

Deepwater loading facilities are a possible short-term solution until dredging is completed to accommodate larger vessels. By placing the offshore facility in a deep water channel or harbor, vessels could avoid restrictive draft limitations. The operations can be located such that the vessel is partially loaded in the port; then, the remaining cargo is loaded at the offshore coal terminal, which is connected by a conveyor belt or slurry pipeline fed from onshore coal facilities. Locating adequate ground storage nearby may be a problem in certain areas. In midstream operation, barge arrivals must be closely coordinated with foreign steam coal carrying vessels.

4.5.2 LASH and Seabee

The barge-carrying ship is a development in international trade peculiar to the U.S. Gulf Coast. The Lash (lighter aboard ship) vessel can accommodate 73 to 89 Lash barges at 400 tons of cargo per barge. A fully loaded Lash vessel can transport 30,000 dwt of cargo. Lash barges are not popular with American waterway operators due to their non-standard dimensions; see Table 4.11.

The Seabee barge has a more standard size with a capacity of 850 dwt. This barge is closer in design to the standard 1,500 ton Mississippi River barge with dimensions of 195 feet long, 35 feet wide and 12 feet deep drawing a 9 foot draft. Approximately 80 of the Seabee barges can be loaded onto the high speed, self-sustained mother ship, which requires 38.7 feet in draft when fully loaded.

Both Lash and Seabee barge carriers have the effective loading or discharging rate of two to three barges per hour, reducing port calls to two days or less. There are inefficiencies, however, with this mode of transportation. The barge carrying ships have a great amount of void spaces between the barges and decks. In addition, the extra weight of the barge structures must be transported and will increase the unit cost of coal.

4.5.3 Alternatives to the Existing Panama Canal

Ship sizes have become an issue of greater concern for routes to Japan and the Orient generally from both the East and Gulf Coasts. Currently, ships transversing the Panama Canal are limited to an overall length of 900 feet, beam of 107 feet and a draft of 35.6 feet. However, alternatives do offer

competition to the Panama Canal. Minibridge trade routes between the United States and the Far East are being used more frequently. This type of transport involves the shipment of goods by both sea and rail. Landbridges offer a similar alternative. A landbridge from Coatzacoalcos, Mexico, to the Pacific port of Salinas Cruz is soon to be operational. It will offer container facilities and rail transport between the two ports.

Bypassing the Panama Canal by large vessels has become another alternative. Most of the bypassing ships are from the United States en route to Japan via the Straits of Magellan at the tip of South America. The economies of scale derived from shipping the longer distance in larger dwt vessels has resulted in increased use of this much longer route. As a result of the use of larger vessels, the Panama Canal Commission is considering steps to improve the existing canal. Projects that are currently underway or planned for the future will increase the Canal from 37 to 40 vessels per day to 42 to 45 vessels per day. Even so, to realize the full economies of scale, the canal will have to be able to service ships with up to 62 foot drafts and 150 foot beams.

A new Panama Canal has been considered for vessels over 100,000 dwt. The Atlantic-Pacific Interoceanic Canal Study Commission recommended in a report to the President in 1970 that a sea level capacity canal be constructed no later than 15 years before the projected date of the use of the supersize bulk carriers. The proposed canal would be 40 miles long and would be constructed a few miles west of the current Panama Canal. However, funds to support the improvements cannot be appropriated from toll revenues and Congress is unlikely to authorize the $20 billion necessary for the new Panama Canal.

4.6 Coal Fired Ships

Because of the large increases in the price of marine fuel oil, the possibilities of returning to the use of coal as an alternative fuel for ships has recently been given considerable attention. However, the dominance of oil as a marine fuel is so great and established that very few coal fired ships have been built during the last 25 years. In fact, only seven coal fired vessels were listed in Lloyds Register for 1980.

Marine fuel oil is currently priced at about $200 per ton whereas coal suitable for bunker is about $40 per ton [12]. Thus, on a per ton basis, oil is now five times more costly than steam coal. It appears this price differential will continue to increase. However, in terms of the cost per unit of energy, bunker oil is only three times more expensive. Even so, coal fired vessels not only represent a cheaper form of fuel, but at the same time, they offer a potential market for steam coal twice as large as the 1978 world seaborne trade for both steam and metallurgical coal.

Some problems are anticipated with the increased use of coal-fired vessels. One such difficulty is expressed in terms of the loss of carrying capacity due to the increased weight and volume of coal bunkers over oil bunkers. Studies show that the increase will be 3.0 to 3.5 times on a volume basis and 2.5 to 3.0 times in terms of weight. There is also a question of availability of bunker coal at economical prices, and of loading facilities at ports throughout the world at both receiving and loading terminals. Ultimately, there is the question of how to deal with the requirements associated with the disposal of ash from the coal fired vessels. It is for these reasons that most authorities contend existing vessels will probably not be modified to use coal. However, Shell Coal International has projected that

by 1985 almost 30 million dwt of dry bulk carriers, with 16 million dwt in vessels over 100,000 dwt, will be built and use 14 million tons of coal per year. They also estimate that by 1990, approximately 100 million tons of coal would be required for ship bunkers annually. As the number of bulk carriers constructed increases due to the coal loading/receiving terminals, the percentage of coal fired vessels constructed will certainly increase.

CHAPTER 5

PRICE COMPETITIVENESS OF ILLINOIS COAL IN EXPORT MARKETS

5.1 Coal Sales and Ocean Freight Rates

Most U.S. coal is sold F.O.B., indicating that it is the purchaser rather than the seller who realizes any savings in ocean transportation costs. This is a crucial point because it raises important questions concerning who should pay for the expansion or other necessary updating that needs to be done to the national port system. In particular, this is a point related to port expansion to accommodate larger vessels. The sale of Illinois coal or any bulk commodity on the overseas market will be partially based on the landed cost of coal. Therefore, ocean freight rates are an important factor in the international sale of Illinois coal.

In order to compare the landed cost of Illinois coal in Europe and the Orient with its competitors, estimates of transportation costs from Southern Illinois to possible ports were estimated, as shown in Table 5.1. These estimates consider three transport modes for the Gulf Coast: rail from mine to port; truck from mine to railhead and rail to port; rail or truck from mine to

Table 5.1

Comparative Transportation Costs from Southern Illinois Mines

(U.S. $/ton)

Modal Combinations	Port: New Orleans	Port: Hampton Roads	Port: Long Beach
1. Rail from mine	8.40	21.50	46.00
2. Truck-rail			
a) truck (mine to railhead)	3.00	3.00	3.00
b) rail line-haul	8.40	21.50	46.00
c) total	11.40	24.50	49.00
3. Barge			
a) mine to river			
rail	1.50-2.75		
truck	3.00		
b) transfer			
loading	1.00		
loss	0.50		
c) barge line-haul	7.50-7.75		
d) total	10.50-12.25		
4. Cost range	8.40-12.25	21.50-24.50	46.00-49.00

Notes

1. Trucking cost estimate assumes a haul of 20 miles at $0.15/ton-mile.
2. All cost estimates reflect economic conditions in August 1982.

Source: University of Illinois estimates.

river and barge to port. The cost estimates reflect economic conditions in August 1982 when both railroads and barge companies were very competitive in their pricing policies.

5.2 European Market

The position of Illinois coal in the export market with respect to its competitors in 1982 is shown in Table 5.2. The table indicates that Illinois coal shipped to Europe via the Gulf Coast offers the most competitive price at $2.07 per million Btu (mBtu). The closest competitor to this price is South African coal at $2.44/mBtu. The most competitive price of Illinois coal, however, was derived assuming various factors including a FOB mine price reflecting the current excess capacity of Illinois coal production.

In the first half of 1981, Illinois coal spot sales have ranged from $25 to $27 for 11,700 Btu/lb, 2.5 percent sulfur and 8.5 percent ash coal. By using the average price ranges, applying a sulfur penalty of $0.50/ton per 0.1 percent sulfur content above 1.5 percent and making a proportional Btu adjustment based on 11,500 Btu/lb of typical European market requirements, the adjusted FOB mine price would be $21.37/ton [15].

Adding $8-12/ton of transportation cost to a Gulf Coast port by rail or barge, the price at the port would range from $29 to $33 per ton. Assuming no demurrage charge, delivered Illinois coal at Northwestern European piers would range from $45 to $52 per ton, including $2-3 per ton port loading cost, ocean freight rates of $12-14 per ton, and $2 per ton unloading cost. Taking the midpoint of the ranges, Illinois coal can be landed at a cost of $2.07/mBtu.

Although a highly competitive price, coal selling for $21 FOB mine in Illinois is not an attractive proposition given current production costs. To

Table 5.2

Indicative Steam Coal Costs and Prices in Export Markets
Comparative Analysis of Illinois Coal and Its Competitors
(U.S. $/ton)

	Price FOB Mine	Mine to Port[b]	Price FOB Port	Port Loading	Ocean Freight	Port Unloading	Delivered Price Range	Midpoint	$/mBtu[a]
Northwest Europe									
From U.S.									
Illinois via Gulf Coast	21	8-12	29-33	2-3	12-14	2	45-52	48½	2.07
Illinois via East Coast	21	21-24	42-45	9-13	12-13	2	65-73	69	2.95
Eastern via East Coast			46-48	9-13	12-13	2	69-76	72½	3.15
From Australia			52	2-3	24-25	2	80-82	81	3.38
From South Africa			41	2-3	13	2	58-59	58½	2.44
Japan									
From U.S. via Existing Ports and Routes Using 60,000 dwt Vessels									
Illinois via Panama Canal	21	8-12	29-33	2-3	30-31	1	62-68	65	2.77
Illinois via Cape Route	21	8-12	29-33	2-3	35-36	1	67-73	70	2.99
Illinois via West Coast	21	47-49	68-70	5-6	11-13	1	85-90	87½	3.79
Western via West Coast			42	5-6	11-13	1	55-61	58	2.42
Eastern via Panama Canal			46-48	2-3	31-32	1	80-84	82	3.57
Eastern via Cape Route			46-48	2-3	34-35	1	83-87	85	3.70
From Australia							59.3	59.3	2.60
From South Africa							44.8	44.8	1.97
From U.S. via Deeper Ports and Canal Using 120,000 dwt Vessels									
Illinois via Cape Route	21	8-12	29-33	2-3	20-21	1	52-58	55	2.35
Illinois via New Panama Canal	21	8-12	29-33	2-3	13-15	1	45-52	48½	2.07

Note: a. Assumes 11,700 Btu/lb., 2.5% sulfur and 8.5% ash.
b. Mine to Port cost estimate from Table 5.1.

Source: [11, 13, 15, 23] and Table 5.1.

operate a new coal mine to cover production costs would require a FOB mine price ranging from $23 to $33 [15]. Once the current excess capacity is absorbed, however, Illinois coal producers can increase a FOB mine price up to $28/ton which makes it equal to delivered South African coal on a quality-adjusted basis.

The indicative price structure shown in Table 5.2, however, cannot be sustained beyond 1982, at which time Australian ports will be able to accommodate substantially larger vessels up to 110,000 dwt. South Africa is also expanding a major port at Richards Bay, and it is expected to accommodate 150,000 dwt vessels by 1985. The ocean freight rate from South Africa to Europe is the same as the rate from the Gulf Coast to Europe, as shown in Table 5.1. New developments in port handling capacity and vessel size increases, therefore, will have profound implications for the future competitiveness of Illinois coal in European markets.

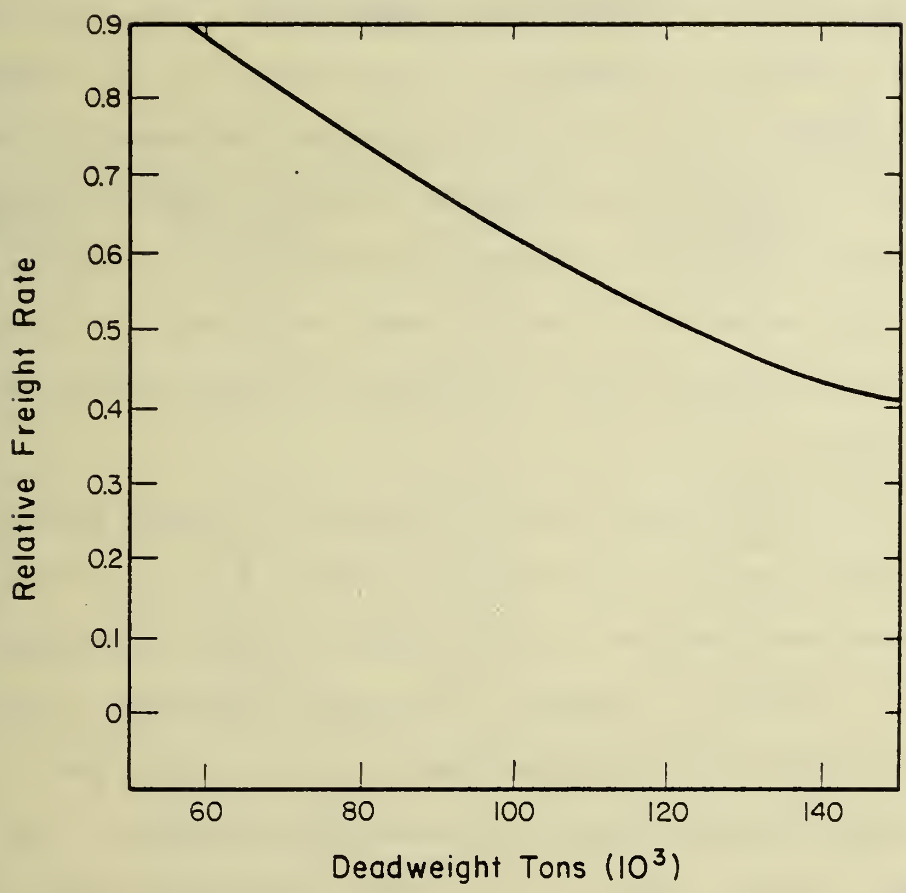
5.3 Oriental Market: The Case of Japan

The estimated delivered price of Illinois coal via the Panama Canal or Pacific Coast is not attractive in current Japanese steam coal markets. Among the possible routes, the existing Panama Canal route is better than the Cape route using 40 foot draft vessels or the Pacific Coast Route. The price of Illinois coal in the Japanese market is high because the ocean transportation component is almost one-half of the total delivered cost.

Larger ship sizes can result in economies of scale with cost savings approaching 25 percent, 35 percent and 45 percent for colliers of 100,000 dwt, 120,000 dwt and 150,000 dwt respectively as compared with Panamax vessels. See Figure 5.1. If 120,000 dwt or larger vessels were used to ship Illinois

Figure 5.1

Economies of Scale Realized in Oceanborne Coal Trade



Source: U.S. Office of Technology Assessment [13].

coal via the Cape route, the delivered price of Illinois coal at Japanese piers could be reduced to \$2.35/mBtu, or \$0.25 less than the current Australian delivered price per mBtu.

The implications of utilizing larger vessels can best be understood by noting that Japan imported 71 percent (or 1.1 million tons) of the steam coal exported from Australia in 1979. During January-June, 1980, total steam coal imports from Australia exceeded 1.2 million tons. H. P. Drewry gave an estimate of single voyage rates for Australian coal shipments in Table 5.3. These figures emphasize the economies associated with the utilization of larger vessels. The rates were estimated on the basis of vessels departing from New South Wales ports fully loaded with coal. The 1985 estimates simulate current rates with built in allowances for cost escalations and other possible effects.

Substantial savings can be seen in the use of larger vessels. Again, using New South Wales as an example, in Table 5.4 we can see the estimated ocean transport costs for coal. In this table, savings are expressed in terms of 1979 U.S. dollars. Therefore, the savings applicable in 1985 would be substantially greater than those indicated.

The long-term implications of utilizing larger vessels to the Oriental market would be far greater if the Panama Canal was not restricted to the Panamax vessels. Illinois coal could land at Japanese piers at \$2.07/mBtu if 120,000 dwt or larger vessels can be used, a rate \$0.53/mBtu less than the Australian coal price and only \$0.10/mBtu higher than the lowest South African price in the current Japanese market for steam coal.

Table 5.3

Estimated Single Voyage Rates for New South Wales Coal Shipments
($US/cargo ton/voyage)

	1979		1985	
Vessel Size (10^3 DWT)	N.S.W. to Rotterdam	N.S.W. to Japan	N.S.W. to Rotterdam	N.S.W. to Japan
75	16.37	8.87	33.86	18.44
100	14.42	7.77	29.63	16.14
125	12.55	6.84	26.40	14.25
140	11.49	6.65	24.05	13.84
160	10.94	6.34	22.70	13.09
200	9.71	5.67	20.32	11.80
250	9.02	5.57	18.94	11.62

Source: Coal Resources Development Committee [3].

Table 5.4

Estimated Sea Transport Costs for Shipment of 0.6 Million Tons of Coal

(U.S. $millions)

Vessel Size (10^3 DWT)	Number of Shipments	Sea Transport Costs (1979 Rates)	
		To Japan	To Europe
75	8	5.32	9.82
150	4	3.90	6.72
200	3	3.40	5.83

Source: Coal Resources Development Committee [3].

5.4 Summary

This analysis of existing transportation facilities clearly indicates that steps must be taken to keep pace with foreign steam coal supplers. The major concern is with the transportation infrastructure. Adequate facilities exist to transport Illinois coal exports by railroad and by barge on the inland waterway system. In contrast, substantial port developments are needed. The national port system is not responding to world shipping demand; growth of U.S. ports has not been stimulated commensurate with worldwide shipping trade. Vessels chosen to ship coal are becoming larger and economies of scale can be realized through their use. Currently, the national port system cannot accommodate these vessels adequately.

As the rest of the world develops its coal handling terminals to respond to the market and achieves economies of scale, the U.S. is just beginning to realize that the current capacity of the national port system will be detrimental to its future coal trade growth. Foreign coal buyers suggest that the United States should concentrate on the development of a few larger deep draft ports that could facilitate vessels as large as 250,000 dwt. The idea of expansion or construction of a new Panama Canal has drawn serious consideration not only from the United States but also from most of the importing countries in the Pacific Rim, including Japan, Korea, Taiwan, and the Phillipines [16]. The research presented here confirms this suggestion, with the reservation that a careful analysis be done to identify more clearly the nature and extent of international coal customers. The Gulf and Pacific Coast ports are beginning to improve and expand to partially alleviate the pressure on the Atlantic Coast and, as a result, possibly reduce the cost of Illinois coal. Many facilities are already in the process of expanding

storage space and upgrading port coal handling facilities. The dredging of channels and harbors is also a positive move towards overcoming the transportation constraints that the United States faces. The Gulf Coast is particularly interested in finding a way to shorten legislative procedures to enable the Ports of New Orleans and Mobile to handle larger vessels.

The economic benefits that will ensue from port development will only be made possible through vast capital expenditures. In the case of steam coal, Illinois is competing in an international market in which other coal exporters have the same or better potential for expansion. If investments are not made in the port and coal terminal infrastructure, Illinois will quickly lose the possibility to compete with other steam coal suppliers.

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PART II

TRANSPORTATION OF ILLINOIS COAL TO THE SOUTHEAST: AN ECONOMIC ANALYSIS OF A COAL SLURRY PIPELINE PROPOSAL

by

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J. Timothy Lefever

CHAPTER 6

INTRODUCTION

6.1 Focus

A bill proposed in 1980 in the U.S. House of Representatives, and concerned with coal slurry pipelines, included in its introduction the following statement:

"The Congress finds and declares that:

1. The increased use of domestic coal to create electrical and other forms of energy promotes the national interest by conserving oil and natural gas resources;

2. Use of domestic coal resources may be facilitated by the construction of pipelines to transport coal from the mine to the consumer;

3. The national interest may, in some situations, be facilitated by authorizing pipeline carriers of coal to obtain rights-of-way across private lands;

4. Regulation of coal transportation by pipeline must be coordinated with existing transportation regulations and be in accordance with national transportation policy; and

5. The provisions of this Act and the amendments made by this Act should not affect the regulation of water rights by the States." See H.R. 6879, 96th Congress, second session,

introduced March 19, 1980, p. 2; see also U.S. House of Representatives [45].

The proposed legislation from which this quotation was taken was entitled, "Coal Pipeline Act of 1980." It would have established procedures for certifying and regulating coal pipeline carriers at the federal level. One of the most important provisions of the bill would have granted authority for pipeline carriers of coal to cross railroad property, an eminent domain measure important to the development of the mode of transport. As with several other similar legislative efforts, the 1980 bill was the focus of a number of economic and political forces. No federal eminent domain legislation has yet been passed, although the same forces continue to generate new proposals and further debate. Each such effort could significantly alter the way in which the energy contained in coal moves from the mine to the consumer, with important national and regional impacts.

The major purpose of this part of the study is to identify and assess some of the potential consequences that a coal slurry pipeline to Georgia, Florida and Alabama might generate for Illinois. We have structured our presentation as a case study that begins with a brief description of coal slurry pipeline technology, its use to date in the United States, and a discussion of the proposed pipeline that is most likely to affect Illinois in the next decade (the Coalstream pipeline).

In Chapter 7 we identify and describe the major forces and issues that surround coal slurry pipelines, both at a national level and with respect to the Coalstream proposal. In the process we describe the major policy alternatives that have emerged in connection with federal legislative proposals, and indicate how various interest groups have reacted to these proposals.

We then turn to a description of market structure in Chapter 8. This entails a characterization of the market for Illinois coal, and the market for the transportation of Illinois coal. With respect to the market for coal itself, we describe the suppliers and consumers of coal, the nature of coal contracts, substitute fuels, and regional demand for coal. In the transportation market, we examine current transportation traffic patterns, comparative costs by mode, delivered coal prices, and other available data affecting coal transportation.

With these basic elements as background, Chapter 9 addresses potential impacts in Illinois of the proposed pipeline, particularly from the perspective of railroad, barge, and motor carrier traffic. It also summarizes some of the foreseeable consequences for coal producers, consumers, and the environment, though in less detail than for the transportation modes. We show that the viability of the pipeline, and hence the magnitude of its economic impact on the Illinois economy, will depend on how rail transportation rates are treated under the Staggers Rail Act of 1980. We will attempt to demonstrate both qualitatively and quantitatively what some of those consequences might be. Chapter 10 provides a summary of our findings, conclusions, and understanding about the importance of uncertainties in the analysis. A word about the latter is appropriate before we begin.

With a new technology, there are obviously few hard data points that can be used to define just what the impacts would be if the technology were implemented. In fact, it is far beyond the scope of this study to provide an independent verification of such items as system costs for various modes or demand data. Nevertheless, we believe that it is useful from the standpoint of policy analysis to pull together a number of the pieces of the policy puzzle that have been studied in the professional literature and presented by

various interest groups in decision-making arenas. Such an effort leads us to identify findings for which there is a consensus, as well as critical areas in which information either is not presently available or is subject to great uncertainty. It is important to know when policy-oriented conclusions are sensitive to a particular type of uncertainty. We view the discovery of such sensitivities as an especially useful aspect of a study of this kind.

6.2 Coal Slurry Technology: A Brief Description

Coal slurry pipeline operations involve the pumping of pulverized coal, suspended in a medium such as water, through a pipe. (There are a number of excellent summaries of coal slurry technology. For example, see Rieber and Soo [23], Volume three, Chapter three.) Once it is mined, the coal is transported to a preparation plant where it is finely ground and mixed with the fluid that will suspend the coal particles. Water continues to be the dominant fluid used for this purpose. A water slurry mixture is typically 50 percent coal and 50 percent water by weight. The resulting mixture is then placed in agitated storage tanks until it is ready for entry into the pipeline. Coal particles in the slurry typically have a maximum diameter of about one eighth of an inch.

Coal slurry pipelines can vary in diameter, with known or proposed systems ranging from 10 to 38 inches. The pipelines are buried and have electric pumping stations placed intermittently along the route to maintain movement of the slurry. The spacing of these pumps depends on a number of technical considerations, included diameter of the pipe, intended slurry velocity, and the nature of the terrain. Pumphouse spacing can therefore range from about 50 to 150 miles.

The slurry typically moves through the system at a rate of about four miles per hour. The systems are designed to maintain flow velocity within a fairly narrow operating range, since major fluctuations in velocity require an expensive system design capable of withstanding the higher pressures and increased power requirements that would be encountered at peak velocities. General engineering considerations require that the flow be maintained at a minimum velocity in order to prevent settling of particles from the fluid suspension.

Once the slurry reaches its destination, it is again stored in a tank until fed into a facility to remove the water called a "dewatering" plant. The coal can be initially separated from the slurry in a number of ways, including centrifuging, filtering, or natural settling. More finely ground particles can be separated by chemical treatment. The coal is then dried and delivered to powerplants.

This brief description suggests a number of potential problems that might be encountered in the operation of a slurry pipeline system. First, is there an adequate source of water? This is a bigger problem in the West than in other areas of the country, because of the generally more arid climate. Second, what is to be done with the water at the receiving end? If the water contains a high concentration of coal particles, disposal can be a problem. Electric utilities may be able to use a portion of the water for cooling purposes. Third, what happens if the system breaks down for more than 72 hours and coal particles settle in the pipeline? If the slurry has to be drained from the pipeline in order to facilitate repairs or flush out a blockage, there may be a need for rather large storage ponds to accommodate the drained slurry. If the slurry is to be reintroduced into the pipeline, then the pond must include agitators to maintain a suspension. If no

agitating capabilities exist at the storage points, then the ponds themselves may pose an environmental hazard, especially as the water evaporates and coal dust is blown away. As is the case with virtually all system designs, much of the hazard potential can be reduced by inclusion of costly safeguards, including extra pumping facilities, heating the pipeline to prevent freezing, higher quality pipe to reduce the probability of leakage, as well as other technical options.

With respect to some of the problems that are directly related to water, we note that there are other feasible slurry suspensions, as discussed in [26, p. 13]. The technology could employ a combustible medium such as oil or methanol, to be burned along with the coal by electric utilities. A noncombustible alternative to water, such as liquid carbon dioxide could also be used as a transport medium. Since liquid carbon dioxide has a viscosity much lower than that of water (1/15 to 1/30), and further because it does not cause the coal to swell, the liquid carbon dioxide slurry can consist of as much as 80 percent coal. At the receiving end, most of the liquid carbon dioxide can be separated from the coal and either recycled (in a closed loop system) or sold commercially (in an open loop system, which uses the transporting medium only once). The balance can be removed from the exhaust gases of the boiler system using commercially available techniques.

6.3 Domestic Coal and Slurry Pipelines

The first major coal slurry pipeline in this country was built in 1957. It connected Cadiz, Ohio, to the East Lake Power Station of Cleveland Illuminating Company, located on Lake Erie. The ten inch diameter pipeline was 108 miles long. At that time rail rates had increased to $3.47 per ton;

when the pipeline was built, it delivered coal at less than $3.00 per ton. The pipeline operated until 1963, when the railroad industry sought approval for new, low rates for unit train movements. The Interstate Commerce Commission allowed a rate of $1.88 for unit trains, and the pipeline cost structure did not permit its survival at the new rate [7, pp. 3-12].

In 1970, the second major U.S. pipeline began transporting coal over a 273 mile route connecting the Black Mesa coal fields in Arizona with the Mohave power plant in Nevada. It is an 18 inch pipeline, capable of transporting about 4.8 million tons per year. At least two important factors have contributed to the success of this pipeline over the last decade. First, its route is much more direct (about 70 percent as long) than the route that would be traversed using the nearest railroad. Second, there is an abundant supply of water available.

Several other coal slurry pipelines are in the planning or proposal stages at present. A summary of these appears in Table 6.1. As the table shows, the proposals represent substantially varied configurations. Capacities range from 10 to 55 million tons per year; lengths of haul range from less than 100 to 1500 miles; pipeline diameters are as large as 38 inches.

6.4 The Coalstream Pipeline Proposal

A major pipeline proposed in the eastern part of the United States is the Coalstream pipeline, formerly known as the Florida Gas pipeline. As Table 6.1 shows, it represents the largest proposed pipeline in terms of capacity (55 milllion tons per year), one of the largest diameter pipelines proposed (36 inches), and one of the longest systems under consideration (1500 miles).

Table 6.1

Proposed Domestic Coal Slurry Pipelines

System	Capacity (Million tons per year)	Cost (Billion $)	Length (Miles)	Diameter (Inches)	Water Requirement (Acre-Ft./Year)	Owners
Snake River Project (NICES)	10	0.3-0.5	1100	20-24	7,500	Northwest Energy Co., Bechtel, Battelle, Gulf Interstate Eng. Co., Dean Witter Reynolds, Inc.
Allen-Warner Valley Energy*	12.5	0.3 for two lines	70	12	2,000	Nevada Power Company and other interests
Pacific Bulk Commodity Transportation System	10	0.5	650	26	8,000	Boeing Engineering and Construction Co.
Texas Eastern	25	1.8	1300	20,38	20,000	Texas Eastern Corp.
Energy Transportation Systems, Inc.	25	2.0	1670	38	15,000	Bechtel Corp., Lehman Bros., Kuhn Loeb, Kansas-Nebraska Gas, United Energy Resources
San Marco Pipeline	10	0.5	900	24	15,000	Houston Natural Gas, Rio Grande Industries
Coalstream Pipeline	25-55	2-3	1500	36	20,000 to 25,000	Continental Resources Co.
VEPCO	5	--	350	--	--	Virginia Electric & Power Company

Sources: Oil and Gas Journal, Sept. 10, 1979, p. 93; Oil and Gas Journal, June 23, 1980. Underlying data from Slurry Transport Association and U.S. General Accounting Office. G. Eatman, "Slurry Pipelines: What Can We Expect and When?" presentation before Transportation Research Board, January 1981.

This pipeline is proposed by Coalstream Pipeline Company, a subsidiary of Continental Group. Continental Group owns the Continental Resources Company which in turn owns and operates a major gas pipeline from southern Texas to Florida. Continental, working with several electric power companies in the Southeast, has proposed a system which would have one gathering line starting at Huntington, West Virginia, and a second at Shawneetown, Illinois. The eastern branch would proceed essentially south through eastern Kentucky and Tennessee into northern Georgia. The western branch is directed southeast from Shawneetown, Illinois, across western Kentucky, central Tennessee, northeastern Alabama, and into northern Georgia, where it would join with the eastern branch northwest of Atlanta. The line would then proceed southeast into Florida, where it would split to serve the east coast as far south as Martin, and the west coast to the Tampa area; see Figure 6.1.

The Coalstream proposal is unlike the western slurry pipeline proposals in at least two major respects. First, the acquisition of water appears to be much less of a problem since the pipeline originates in areas with relatively large water supplies. Second, eminent domain legislation is a virtual necessity if this pipeline is to be constructed, since it would traverse many railroad rights of way, and travel over a much smaller percentage of federal lands than is generally found along the western routes.

6.5 A Warning: Keeping the Big Picture in Mind

Before beginning the detailed analysis, we believe that it is imperative to paint a clear picture of the task we undertake here. In what follows there will be a rather extensive amount of market structure and cost data, coming from a number of sources. It may be tempting to quibble about whether these

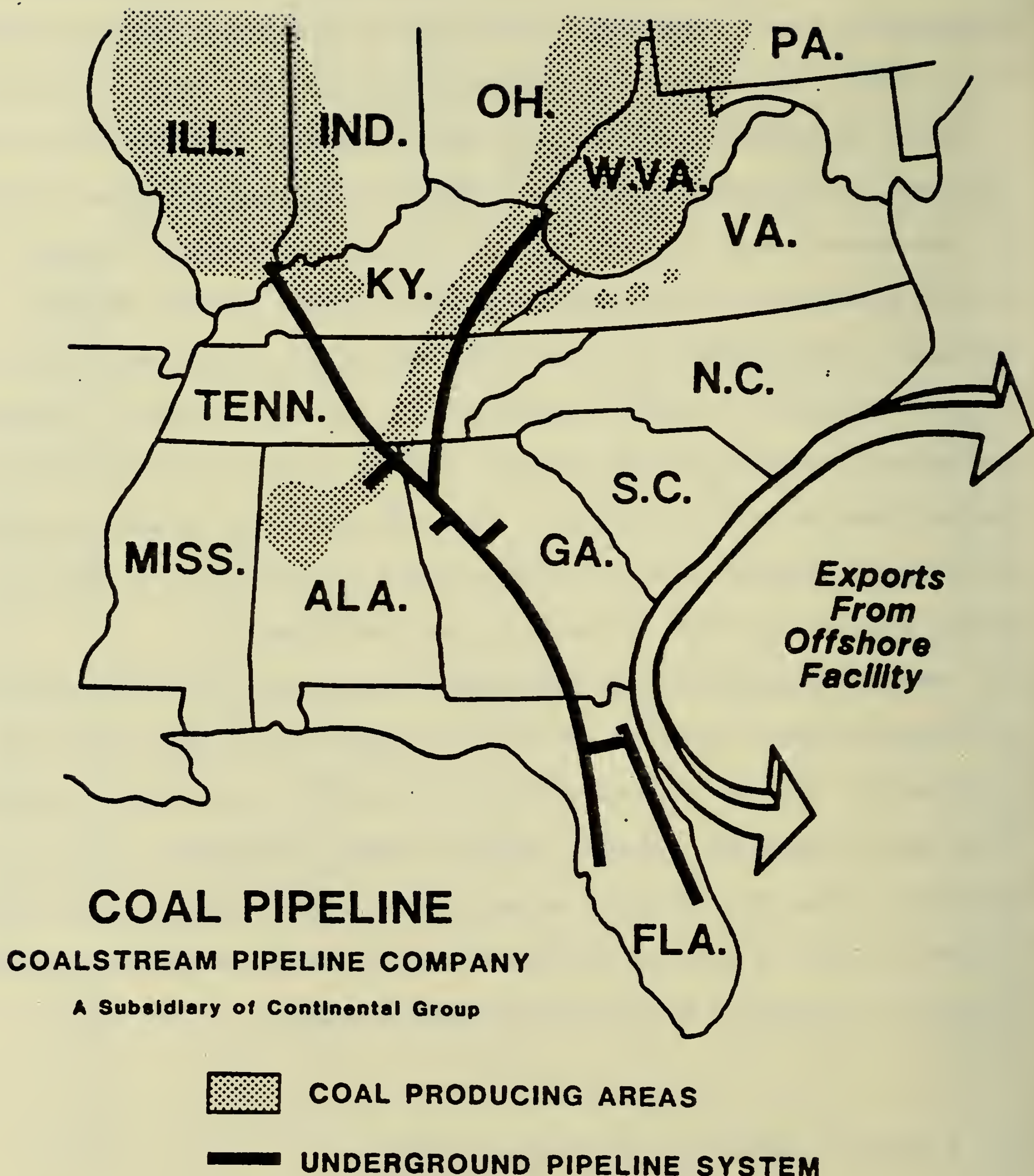

Figure 6 .1.

Source: A.D. Dorris, "Pipeline Transportation of Slurry Coal for the Southeast Market and for Export," conference paper Southern Illinois University, July 1981.

numbers are correct, or should be adjusted up or down by a few percent. To become immersed in debates of these kinds will almost surely mean that the reader will miss the proverbial forest for the trees. To bring this warning home, we will provide in this section a methodological roadmap for our analysis. The ultimate quantitative conclusions depend on the results of the following steps.

<u>Step 1. Effects of the Staggers Act</u>

Under the Staggers Act of 1980 (discussed in Section 9.3 below) railroads can presently, without further government intervention, charge any rates for coal movements greater than average variable cost and less than a specified multiple (e.g. 1.6) times average variable costs. Most coal movements in this country are currently made at rates near the maximum allowed under the Staggers Act. However, if competition from coal slurry pipelines occurs, railroads are likely to lower their rates as much as necessary to retain the business; it could be in a railroad's profit maximizing interest to lower its rates even as low as average variable cost if necessary to meet competition from a pipeline.

<u>Step 2. Cost Comparisons</u>

A railroad may lower its rates most of the way to <u>average variable</u> cost and still find coal movements profitable, since any rail rate above average variable cost contributes something toward the common or fixed costs of the firm. The rest of those fixed costs would have to be covered by revenues from other (non-coal) freight carried by the railroad.

A pipeline's cost structure is different; it carries only a single product, coal slurry. All of the fixed costs of a pipeline operation must be covered by revenues generated from coal slurry movements. Therefore, in order for a pipeline to be profitable, total revenues must equal or exceed total

costs, or equivalently price must equal or exceed <u>average</u> <u>total</u> cost.

In short, economic theory provides a guideline for the cost comparison that is relevant in the case of coal slurry and railroad intermodal competition: the average total cost of the pipeline and the average variable cost of the railroad. Consider the following three cases:

<u>Case</u> <u>1</u>. Railroad average variable cost and pipeline average total cost are approximately equal. In this case one would expect that rail rates might drop from 1.6 times the rail average variable cost perhaps all the way to average variable cost, resulting in a rate decrease of as much as 37.5 percent.

<u>Case</u> <u>2</u>. The average varaible cost of the railroad is less than the average total cost of the pipeline. In this case the railroad can render the pipeline unprofitable, perhaps with a rate decrease of less than 37.5 percent.

<u>Case</u> <u>3</u>. The average variable cost of the railroad is greater than the average total cost of the pipeline. In this case the pipeline can meet railroad competition, even if the railroad lowers its rate all the way down to its average variable cost. But, the pipeline could set its rate just below the railroad's average variable cost, since that would be the minimum rate that the railroad could seek under the Staggers Act.

These three cases cover all of the possibilities. Note that the maximum rate decrease that would occur would be about 37.5 percent in any case. This observation is central to our analysis and demonstrates why <u>a detailed comparison of costs among the modes is not imperative</u> if the research effort is intended to demonstrate the <u>maximum</u> effect the coal slurry pipeline could have on transport rates.

For completeness in this study, we have included some information that attempts to approximate the comparison between average variable costs of the

railroad and average total costs of the pipeline. For many reasons it is difficult to say exactly what these costs are. For example, it is not easy to say, based on cost studies cited in this work, just how much maintenance on railroads should be charged to coal movements. Some crude estimates are cited, but it is not an easy task to validate numbers. Fortunately, for our purposes it will not be necessary to obtain exact figures, for reasons discussed above. Once again, the central point is that we are examining the maximum potential impact of a coal slurry pipeline; therefore, we can concentrate on the maximum rate reduction that might result from the new form of intermodal competition.

Step 3. Maximum Potential Increases in Coal Movements to the Southeast

Once the crucial issue of Step 2 is understood, it then becomes a straightforward calculation to determine how a maximum transport rate decrease of 37.5 percent would affect the quantity of Illinois coal moved to Florida, Alabama, and Georgia. These calculations are performed in detail in Section 9.6. They are based on elementary economic principles, which are only briefly described here.

a) Since coal transportation charges typically account for less than 20 percent of delivered coal prices for shipments to Florida, a maximum 37.5 percent reduction in transport rates would lead to a maximum reduction of 7.5 percent (0.2 x .375) in delivered coal prices.

b) A 7.5 percent decrease in delivered coal price would lead to an increase of coal consumed in the Southeast of about 3.75 percent, assuming a typical coal price elasticity of demand equal to -0.5. Since the Coalstream pipeline would bring coal not only from Illinois, but also from the Appalachian coal producing area, to the Southeast, reductions in coal shipment rates from Illinois and the Appalachian region will probably be similar.

Thus, one would expect the effects of increased consumption in the Southeast to be spread across the Illinois and Appalachian regions. In short, a coal slurry pipeline will probably increase the movements of Illinois coal to the Southeast by no more than 3.75 to 4.0 percent, relative to the level that would be observed if no pipeline were built.

c) Since about 10 percent of the coal produced in Illinois and sold to electric utilities was sold to utilities in Florida, Alabama, and Georgia in 1980, the total increase in production of Illinois coal will probably be increased by no more than one percent if a coal slurry pipeline is built, relative to the level of production that would occur if no pipeline were built.

All of this explains the importance of our subsection title, "A Warning: Keeping the Big Picture in Mind." It is easy to become wrapped up in second order details about relative costs. We have focused on a maximum plausible rate reduction in this study, regardless of the relative costs. The rate reductions could be dramatic, as much as 37.5 percent. But straightforward calculations based on fundamental economics leads us to conclude that even with the maximum possible rate reductions, the quantitative impacts in terms of coal shipped are likely to be small for Illinois coal.

CHAPTER 7

FORCES AND ISSUES

7.1 Forces

It is not difficult to identify several major interest groups that have exerted pressure in public policy debates over slurry pipeline legislative proposals. One could pick up any of a number of hearing transcripts before subcommittees of the U.S. House of Representatives or Senate, and see the forces at work. Some of the major factions include the following:

1. The agricultural interests want to ensure that coal slurry pipelines will not remove ground water from an area whose agricultural health is dependent on continued supply of water. Furthermore, the farming community is concerned that if coal traffic is diverted away from railroads, service may be discontinued on some routes, and increased rates may follow on other routes as the fixed costs of railroad plant are distributed over the remaining traffic.

2. The coal slurry pipeline companies and the Slurry Transport Association obviously seek entry into the coal transport business, and therefore work to minimize resistance to their entry. They have sought eminent domain legislation as a critical part of their development.

3. The <u>public utilities</u> and other consumers of energy would welcome slurry pipeline transportation as an alternative to other modes. This would reduce the number of electric utilities who presently have no viable alternative to railroad transport in their efforts to acquire coal.

4. <u>Environmentalists</u> are concerned with a number of potential effects of slurry pipelines. These include adequate supplies of source water, potentially harmful effects of disposal water, potential effects of leakage, drainage ponds, and water used for flushing when blocked pipelines are serviced.

5. The <u>railroads</u> are concerned that the advent of slurry pipelines will make it even more difficult to earn a normal return on capital. William H. Dempsey, President of the Association of American Railroads, has testified before Congressional committees more than once to present objections to eminent domain legislation. Some of his comments are as follows:

> "Last year [1977] it [our rate of return] was 0.128 percent. In 1976, it was 1.49 percent. In 1975, it was 1.2 percent . . . . Indeed we have not had a rate of return as high as 3 percent since the 1960's, and as high as 4 percent since the 1950's [46, p. 285]. The emphasis upon coal as a transition fuel comes at a time of our greatest financial difficulty in the industry and promises, in the Midwest in particular, to be a major part of the difficulties in the Midwest." See also [45,p. 96].

While there are obviously questions about the size of coal demands over the next few years, and about the way in which that traffic splits among the modes, the statement by Mr. Dempsey reflects a widespread concern that without the coal traffic, railroads will have a very difficult time earning a normal return on their investment.

6. The <u>pipeline construction workers</u> favor the legislation because it means more jobs for them. Martin J. Ward, general president of the United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting

Industry of the United States and Canada argued in 1978 that joblessness in construction was at nearly twice the national average. "So the pipeliners available for this job are the Teamsters, the Laborers, the Operating Engineers and the other trades whose skills will be called upon to build these pipelines." [46, p. 277]

7. The railroad workers oppose the legislation because they believe that the railroads can handle the increased coal demand quite well, and that railroads are at least as energy efficient as pipelines. The jobs of rail workers will be jeopardized, they argue, if the coal slurry pipelines are granted eminent domain. See the testimony of James R. Snyder, chairman, legislative committee, Railway Labor Executives' Association, in [46, pp. 115-117].

8. The coal producers favor the legislation since it would create more ways for their products to reach energy consumers and electric utilities.

This list is not intended to be exhaustive, but it does serve to identify the major players in the legislative game.

7.2 Issues

In our discussions of forces, we have suggested a number of issues at the center of the policy debate. We now enumerate the issues more systematically, and briefly describe why they are important.

1. Will coal slurry pipelines provide less costly transport than barges, unit trains, or any other mode or combination of modes?

At the core of this issue is the following basic concern. If slurry pipelines do not provide a lower cost alternative to railroads, then on what basis is their construction and operation socially desirable? If lower costs

are to be realized with slurry pipelines, then do railroads lose business that further increases their costs of service to other (e.g., non-coal) customers?

The comparison of costs will not be easy, since railroads provide many services over the same track used by coal operations. We elaborate further on this in Chapter 8. Still, one can address certain basic questions, including how slurry pipeline costs depend on water availability, length of haul, pumping fuel prices, volumes to be moved, and other parameters likely to affect costs.

2. Will railroad profitability be severely reduced by coal slurry pipelines?

There are three main points here. First, will coal slurry pipelines charge rates that divert much rail traffic? Second, will railroads be allowed to respond to new slurry rates with rates of their own choosing? Third, if railroads lose significant traffic to pipelines, will the remaining railroad customers be left with much more costly operations as the fixed costs of railroads are distributed over fewer units of output and fewer services?

3. Should eminent domain be granted to coal slurry pipelines?

Is federal legislation necessary, or should eminent domain be left to the states? If such legislation is passed, how are eminent domain authorities to be implemented? This is the most pressing issue in current regulatory debates.

4. Should coal slurry pipelines be regulated as common carriers?

There are several issues at stake here. Should pipelines be required to expand facilities to meet demand? Pipelines have rather inflexible design characteristics, as noted in Chapter 6. Pipeline expansion cannot be done on an incremental basis, by adding another car as railroads do. Expanded

capacity can require huge investments, especially if new pipelines have to be built.

Under the same heading (common carriers), should pipeline construction require certification of public necessity and convenience? If so, who does the certifying: the Interstate Commerce Commission, the Federal Energy Regulatory Commission, or some other agency? Can pipelines abandon operations at will?

5. Are pipelines to be subject to price regulation?

If so, who sets the prices (FERC, ICC), and how? FERC currently regulates oil and gas pipeline transport tariffs. If FERC controls coal slurry prices, will that form of regulation be coordinated with rail transport prices under the jurisdiction of the ICC? We will pursue this point further in Chapter 9.

6. Will coal slurry pipelines use water vitally needed for agricultural or other purposes, especially in the western part of the country?

How will state and federal water laws be administered and interpreted as coal slurry pipelines are developed? Water laws are extremely complicated, and often depend on whether one body of water is connected with another one, whether interstate interests are affected, and on historical use patterns. Some interesting and complex possibilities can occur. For example, suppose at the time of construction of a slurry pipeline, the water source is thought to be independent and not connected with any other source, and water rights are secured from the appropriate entities under those assumptions. Then, at some later time, new geologic evidence establishes the fact that the source in question is in fact connected to another body of water, a discovery that changes the political boundaries of the water control as well. How will such occurrences be resolved?

7. What are the major environmental consequences of the advent of coal slurry pipelines?

The field here is indeed a broad one. Are there adequate levels of safeguards against environmental damage from leakage, disposal water, drainage ponds, and possible pipeline failures? How do the environmental aspects of coal slurry pipelines compare with those of alternative transport modes?

8. To what extent should producers of coal or consumers of coal, including electricity, be allowed to own coal slurry pipelines?

To see why such a restriction has sometimes been suggested, consider the following example. Suppose a regulated local utility is vertically integrated with (i.e., owned by the same company as) a pipeline company that provides most of the coal slurry it needs for its power requirements. There are incentives for the pipeline to charge a price that generates extranormal economic profits. An independent utility would object to this price, since lower transportation costs are desirable from the viewpoint of the electric utility. However, in the vertically integrated case, the electric utility may be content to pass the increased transport prices along to consumers, since there are potentially large extranormal profits to be earned by the sister (transport) company. A similar scenario could be painted for the vertically integrated producer and pipeline company.

This issue is complex. If regulators do their jobs of scrutinizing transport tariffs so that no extranormal profits are earned, then the purpose of such a restriction no longer exists. But transportation contracts are usually quite complicated for pipelines (at least this is so for natural gas pipeline transportation), so it may not be an easy matter to determine whether or not a price is yielding a normal return on investment.

On the other side, some of the firms most interested in getting a pipeline established are producers of coal and local utilities. They may very well be able to provide crucial capital for pipeline construction. Thus, depriving them of participation in ownership of a pipeline could impede pipeline construction, depending on the availability of alternative sources of capital.

7.3 Legislation

The issue of eminent domain for coal slurry pipelines dates back to the early 1960's. In an interesting summary of legislative efforts up to 1976, Professor T. Campbell [5, p. 5] notes:

> "Efforts were made in the early 1960's by Congress to enact a slurry pipeline bill . . . . Coal industry spokesmen were critical of the railroads for refusing to permit slurry pipelines to cross their tracks. No line can be constructed from either of the major coalfields to the principal coal markets without going either over or under railroad tracks. The National Coal Association issued a statement in 1962 that several railroads had refused to permit coal pipelines to pass beneath their tracks, though they grant such permits as a matter of course to pipelines carrying other forms of energy."

If eminent domain was an issue as early as 1960, why was it not a problem in the construction of the Black Mesa pipeline when it was built in Campbell [5, pp. 12-13] offers a two-part answer to this question. First, the pipeline offered no direct competition to any existing railroad. Existing railroad routes were quite circuitous, and there were no apparent plans for construction of new rail facilities. Second, the Black Mesa pipeline is owned and operated by a subsidiary of Southern Pacific Transportation Company. Thus, despite the fact that three rights-of-way of the Santa Fe railroad were crossed, the eminent domain issue was not pursued.

During the 1970's, as more coal slurry pipelines were proposed, the eminent domain issue became increasingly visible. Nearly every year since 1970 at least one bill has been proposed to grant eminent domain legislation; see Table 7.1.

Of course, these bills have not been carbon copies of one another. Some have taken stronger stances on whether electric utilities should own pipelines than others. They have also varied as to the need for common carrier status for slurry pipelines. Over time, regulatory responsibility has shifted from the Interstate Commerce Commission, at least for ratemaking purposes, to the Federal Energy Regulatory Commission (FERC), following its creation in 1977. Still, the bills have been centered around the establishment of eminent domain authority for coal slurry pipelines.

One recent bill on which hearings were held was H.R. 6879 which was proposed by Representative Staggers in March 1980 [45]. This bill was called the "Coal Pipeline Act of 1980," and attempted "to establish a procedure for the certification and regulation of coal pipeline carriers, to provide for the regulation by the Federal Energy Regulatory Commission of certain prices of pipeline-transported coal, and for other purposes."

The Act would have empowered FERC to approve a slurry pipeline request for "a right-of-way for the construction and operation of a pipeline over, under, upon or through any property or facility owned by a rail carrier providing transportation . . . ." The Commission would have been empowered to approve such a request if "(a) the construction and operation of the coal pipeline does not unreasonably interfere with operation of the rail carrier whose property would be crossed; (b) the pipeline carrier of coal agrees to pay the rail carrier for the right-of-way provided; (c) the proposed acquisition is in the public interest; and (d) the terms of the construction

Table 7.1

Selected Summary of Coal Slurry Pipeline Bills

Year	Title	Numbers
1974	Coal Pipeline Act of 1974	S-3870
1975	Coal Slurry Pipeline Act of 1975	HR-1863 HR-2220 HR-2553 HR-2986
1977	Coal Pipeline Act of 1977 Coal Transportation Act of 1977 Coal Pipeline Act of 1977	HR-1609 S-1492 S-707
1979	Coal Pipeline Act of 1979	HR-4370
1980	Coal Pipeline Act of 1980	HR-6879
1981	Coal Pipeline Act of 1981	(Introduced in the House, July 22, 1981.)

and operation (including the amount of payment) are just and reasonable." If the two parties cannot agree on fair payment terms, the Commission may set the terms.

The 1980 legislation would have also required pipeline carriers to obtain a certificate of public convenience and necessity, to submit evidence of technical and financial capability, and to charge rates lower than those which would have prevailed absent the pipeline. Importantly, such pipelines would have had to take on common carrier obligations, including adding capacity "to meet the requirements of coal producers and users that might reasonably be anticipated" [45].

Although this bill did not pass, it contains most of the elements that future legislation will probably contain if eminent domain ever does pass, especially given the now lengthening history of these proposed bills. In Chapter 9, we will assess some potential consequences further. But first, we must address the nature of the markets involved extensively. This is the task to which we now turn.

CHAPTER 8

MARKET STRUCTURE

8.1 The Market for Illinois Coal

8.1.1 Coal Production

Domestic production of coal has been growing over the last decade and has increased significantly in 1979 and 1980. Table 8.1 gives the production of bituminous coal, lignite, and anthracite since 1973 in the United States. Nine major coal supply regions within the contiguous U.S. can be identified. Table 8.2 shows which states are associated with each region.

Illinois is in the Eastern Interior production region and is ranked fourth behind Kentucky, West Virginia, and Pennsylvania in production. Within Illinois, 22 counties reported coal production in 1979 with the southern counties of Perry, Randolph, Franklin, and Jefferson being the largest producers respectively, extracting more than 28 million tons. Nearly 60 million tons of coal were produced in 1979 representing 7.7 percent of total

Table 8.1

Annual Domestic Coal Production

Year	(Thousand tons) Production
1973	598,568
1974	610,023
1975	654,641
1976	684,913
1977	697,205
1978	670,164
1979	781,134
1980	835,400

Source: U.S. Dept. of Energy, Monthly Energy Review, [40, p. 58]

Table 8.2

U.S. Coal Supply Regions

Region	States
Northern Appalachia	PA, MD, OH
Central Appalachia	WV, VA, KY(east)
Southern Appalachia	TN, AL
Eastern Interior	IN, IL, KY(west)
Western Interior	IA, KS, MO, OK, AR
Northwestern	MT, ND
Central Western	WY, UT, CO
Southwestern	AZ, NM
Texas	TX

Source: Office of Technology Assessment, [32, p. 34]

domestic production. Table 8.3 shows total annual coal production for Illinois since 1970. Table 8.4 ranks the operators according to an annual production and gives the counties in which they operated. Only mines which exceeded an annual production of one million tons of coal in 1979 are included.

8.1.2 Coal Consumption

Annual domestic consumption of coal has steadily increased in all but one year (1978) since 1973. In each year, although some coal was imported, a far greater amount was exported as domestic production exceeded domestic consumption. Table 8.5 shows the trend of total annual domestic consumption along with the steady yearly increase in coal use by electric utilities within the U.S.

For Illinois coal in particular, total consumption including in-state, out-of-state, and exports declined irregularly since 1973 but increased dramatically in 1979. Illinois coal consumed by electric utilities both in-state and out-of-state has also declined irregularly. Table 8.6 shows the annual combined in-state and out-of-state consumption of Illinois coal for all users and consumption by both in-state and out-of-state electric utilities since 1973.

Table 8.6 illustrates that although shipments to in-state electric utilities has been declining, the shipments to out-of-state utilities is generally increasing. Much of the in-state utility use of coal is from the western states because of its low sulfur content. In fact, from 1976 to 1977, coal shipments to Illinois from the states increased 82.5 percent.

Table 8.3

Annual Illinois Coal Production

Year	(Thousand tons) Production
1970	64,884
1971	58,415
1972	65,521
1973	61,549
1974	58,073
1975	59,539
1976	58,136
1977	53,136
1978	53,880
1979	48,744
1980	59,538

Source: Illinois Dept. of Mines and Minerals, 1979 Annual Coal, Oil, and Gas Report, [16, p. 21]

Table 8.4

Illinois Mining Companies, Counties of Operation, and Production in 1979

Company	Counties of Operation	(Thousand tons) 1979 Production	Percent of Illinois Production
Peabody Coal Co.	Christian, Randolph, St. Clair	11,018	18.5
Consolidation Coal Co.	Jackson, Montgomery, Perry, Randolph	9,020	15.2
Freemand United Coal Mining Co.	Jefferson, Macoupin, Perry	7,381	12.4
Amax Coal Co.	Fulton, Perry, Wabash	6,537	11.0
Old Ben Coal Co.	Franklin	5,465	9.2
Southwestern Illinois Coal Corp.	Perry, Randolph	4,713	7.9
Zeigler Coal Co.	Douglas	3,804	6.4
Inland Steel Coal Co.	Jefferson	3,753	6.3
Montery Coal Co.	Clinton, Macoupin	1,942	3.3
Midland Coal Co.	(N)	1,902	3.2
Sahara Coal Co.	(N)	1,374	2.3

(N)=No single company mine produced at least 1 million tons in 1979.

Source: Illinois Dept. Mines and Minerals, 1979 Annual Coal, Oil, and Gas Report, [16, pp. 46-49]

Table 8.5

Coal Consumption of Domestic Users and Electric Utilities

(Thousand Tons)

Year	Total Domestic Consumption	Electric Utilities	Percent used by Electric Utilities
1973	562,584	389,212	69.2
1974	558,402	391,811	70.2
1975	562,641	405,962	72.2
1976	603,790	448,371	74.3
1977	625,291	477,126	76.3
1978	625,225	481,235	77.0
1979	680,524	527,051	77.4
1980	706,024	569,273	80.6

Source: U.S. Dept. of Energy, Monthly Energy Review, [40, pp. 58,60] pp. 58, 60.

Table 8.6

Consumption of Illinois Coal

(Thousands of tons)

Year	All Users	All Electric Utilities	In-state Electric Utilities	Out-of-state Electric Utilit
1973	62,542	49,705	24,091	25,614
1974	59,085	46,856	21,828	25,028
1975	60,029	49,284	22,006	27,278
1976	58,526	48,950	21,414	27,536
1977	54,326	45,105	18,432	26,673
1978	48,490	(NA)	(NA)	(NA)
1979	59,349	49,850	18,867	30,983

Note: Total consumption sometimes exceeds total production as listed on Table 8.3 because small local mines were not included in Table 8.3.

Sources: (1) DOE/EIA, Bituminous and Subbituminous Coal and Lignite Distribution -- 1979, [36, pp. 7, 34, 97].

(2) Samson [23, p. 14]

Some idea of which electric utilities are served by Illinois coal can be developed by tracing the shipments of coal to the major consumers inside and outside of the state. Table 8.7 illustrates these movements. This table shows that in 1980 approximately 6.45 million tons of Illinois coal moved to electric utilities in the states of Florida, Alabama, and Georgia. This represents about 12.3 percent of the total amount of Illinois coal sold to electric utilities in the country. Further, approximatley 62 million tons of Illinois coal were produced in 1980, according to Table 4 of the DOE/EIA report on Coal Distribution: January-December 1980. Thus, the 6.45 million tons of Illinois coal sold to electric utilities in Florida, Alabama, and Georgia represent about 10.4 percent of the total production of Illinois coal.

The price of coal has been rising steadily since 1973. Table 8.8 gives the average delivered price of coal to steam-utility plants in the continental United States relative to other fossil fuels which are potential substitutes. This table helps explain the recent trend from oil and natural gas to coal by the electric utilties. In 1980 the energy equivalent price of coal was one-third of the price of oil and two-thirds of the price of natural gas.

8.1.3 Nature of Coal Contracts

The electric utilities are very concerned about the continuity and reliability of fuel delivery. They will often forego a less reliable fuel source at a lower cost for one that is more likely to provide an uninterrupted flow. This risk aversion attitude leads to long-term contracts with fuel suppliers. Until passage of the Staggers Act of 1980, the railroads were restricted from entering into long-term contracts with customers. But presently, they stand on equal ground with other unregulated transport modes

Table 8.7

Electric Utility Consumers of Illinois Coal - 1980

(Thousands of Tons)

State	Consumption	Percent
Illinois	18,700	35.7
Missouri	12,649	24.1
Indiana	7,616	14.5
Wisconsin	2,805	5.4
Alabama	2,480	4.7
Georgia	2,457	4.7
Iowa	1,644	3.1
Florida	1,513	2.9
Minnesota	723	1.4
Michigan	590	1.1
Tennessee	519	1.0
Mississippi	473	0.9
Kentucky	222	0.4
	Total 52,391	100.0

Source: DOE/EIA, Coal Distribution: January-December 1980, [36, Table 9].

Table 8.8

Increase in Fossil Fuel Prices, 1973-1980

(Cents/million Btu)

Year	Coal	Oil	Natural Gas
1973	40.5	78.8	33.4
1974	71.0	191.0	48.1
1975	81.4	201.4	75.4
1976	84.8	195.9	103.4
1977	94.7	220.4	130.0
1978	111.6	212.3	143.8
1979	122.4	299.7	175.4
1980	135.2	427.9	212.9

Source: DOE/EIA, Monthly Energy Review, [40, p. 89].

to engage in contracts of unrestricted length.

8.1.4 Projection of Demand

Sizeable coal reserves exist in the eastern interior region of the U.S. made up for the most part by the state of Illinois. The rate of production from these large reserves of Illinois coal will obviously depend, among other things, upon the growth of demand.

When predicting the future utility demand for Illinois coal several nonmarket factors must be considered. First, the Powerplant and Fuel Act of 1978 provides guidelines concerning fuel use by new and existing electric utilities. Depending upon how this Act is interpreted, it could exert significant influence upon the market for coal by requiring, for example, that all electric utilities burn coal by the year 2000. Second, future federal restrictions on the use of nuclear power and natural gas are uncertain and could have a potentially large effect upon future coal demand. Third, federal and state environmental emission regulations, if tightened, could significantly increase the cost of burning coal by requiring sizeable investments in emission control equipment or coal scrubbers to reduce the sulfur content in coal. This is an especially important issue for consumers and producers of Illinois coal, since its sulfur content is nearly the highest in the nation.

Domestically, the consumption of coal is expected to continue to grow. The electric utilities, which use the lion's share of domestic coal, have increased their demand for coal at an average annual rate of 6.3 percent since 1974 as shown on Table 8.5. Table 8.9 below gives the projections by several private, governmental, and independent organizations of total coal demand and

Table 8.9

Coal Demand Forecasts - 1985

(Millions of tons)

Organization	Total Demand	Utility Demand
U. S. Bureau of Mines	998	704
Federal Energy Administration	1040	715
Amax Coal Co.	1127	806
Shell Oil Co.	1150	690
ICF Inc.	1030	-
National Electric Reliability Council	--	827
Average	1069	748.4

Source: W.J. Maloney, "Energy Demand/Slurry Pipelines/and Coal Supply," Proceedings of the 2nd International Technical Conference on Slurry Transportation, 1977, p. 22 [20].

demand by U.S. electric utilities in 1985. These forecasts indicate an average of 36 percent increase in total coal demand and 32 percent increase in coal demand by utilities over 1980 demand. It is interesting to point out that NERC, ICF, and AMAX had overestimated coal demand by utilities in 1980. USBM, SHELL, and FEA were low. Their 1980 composite average missed by only 15 million tons, or less than 3 percent.

Several studies predict an increased demand for coal by electric utilities in regions currently supplied by Illinois as well as regions to be served by the slurry pipeline. See Boyce et al. [4, p. 14, 18]. K. A. Ebeling [11] anticipates that the SERC region will be served through the 1980's primarily by interior and eastern region coal. Coal shipments to Georgia, Alabama and Florida from Illinois mines are predicted to grow significantly in the 80's while large additions to steam-electric generating capacity in these three states are expected by 1987 [7, p. 4-2]. A tripling in anticipated coal usage in Florida from 1980 to 1988 was forecast by the Florida utilities in 1979. No new nuclear units are planned to be built in Florida before 1990; and the contribution of nuclear power is expected to decrease from 20 percent in 1977 to 18 percent in 1988.

Forecasting the demand for Illinois coal is subject to many additional uncertainties. Whether or not Illinois coal is chosen by new electric generating facilities, or substituted for a fuel currently used, depends upon the factors influencing the cross-elasticities of demand among potential substitutes. These include the characteristics of Illinois coal which bear upon its ease of substitutability. Relevant here is the ability of Illinois coal to meet a diverse set of boiler specifications. Its sulfur, moisture, and ash content affects its burning efficiency. Each of these factors affects the coal's cost per Btu. Illinois coal can be blended, as it is now, with

other coal to meet specific boiler requirements. However, high sulfur Illinois coal often requires scrubbing to meet federal and state emission requirements, which represents an additional cost to the utilities. Thus, the technical requirements, cost of preparation and use, and delivered price of Illinois coal are the factors which will largely determine the extent of its further use.

8.2 Transportation of Illinois Coal

8.2.1 Current Coal Transport Patterns

Most of the coal produced in Illinois is moved by truck, barge or rail. This is indicated in Table 8.10, which shows how Illinois coal is transported to domestic origins by types of consumers. A percentage breakdown for all movements of Illinois coal, as well as for Illinois coal shipped to electric utilities, is presented in Table 8.11. Table 8.12 gives the amounts of coal carried directly from Illinois mines by the major railroads. Although 13 railroads are involved in coal carrying operations, the six largest account for 94 percent of the annual tonnage.

From the mine mouth, Illinois coal travels directly to consumers by rail or truck, or is transloaded onto barges for movement on the inland waterways. Table 8.13 gives primary transport mode(s) of Illinois coal to the electric utilities in the states listed on Table 8.7 ranked according to the amount of Illinois coal which they consume annually for all uses -- industrial, utility, and other.

Table 8.10

Domestic Distribution of Illinois Coal by Method of Transportation: January - December 1980

(Thousands of tons)

	Rail	River	Great Lakes	Tidewater Piers, Coastal Ports	Truck	Tramway, Conveyor, Slurry Pipeline	Total[b]
Electric Utilities	31,170	16,582	295	174	2569	1915	52,705
Coke Plants	2,880	--	--	--	74	--	2,953
Other Industrial	2,551	991	179	--	2414	--	6,181[c]
Residential/Commercial	28	5	a	--	104	--	157[c]
Total	36,629	17,578	474	174	5161	1915	61,996[c]
Percent of Total	59	28	1	--	8	3	100

[a] Value less than 500 tons.
[b] Totals may not equal sum due to independent rounding.
[c] Includes coal distribution data where method of transport is unknown.

Source: DOE/EIA, Coal Distribution: January - December 1980, April 7, 1981, Table 8, [36].

Table 8.11

Percentages of Illinois Coal Moved by Various Transportation Modes to Domestic Destinations, 1980

	Coal Consumed by Electric Utilities	All Coal
Rail	59.1	59.1
River	31.5	28.4
Great Lakes	0.6	0.7
Tidewater Piers, Coastal Ports	0.3	0.3
Truck	4.9	8.3
Tramway, Conveyor, Slurry Pipeline	3.6	3.1
Total	100.0	100.2[a]

[a] Total differs from 100.0 because of independent rounding.

Source: Table 8.10

Table 8.12

Railroads Serving Illinois Mines - 1979

Railroad	(Thousands) Tons Shipped	Percent of Tons Shipped
Missouri-Pacific	16,777	36.9
Illinois Central Gulf	10,501	23.1
Burlington Northern	5,582	12.3
Peabody (a)	4,236	9.3
Chicago North Western	2,854	6.3
Conrail	2,847	6.3
Southern	1,297	2.9
Chicago Rock Island & Pacific	643	1.4
K.R.P. (a)	508	1.1
Illinois Terminal	109	.2
Baltimore-Ohio	97	.2
Louisville-Nashville	36	< .1
Chicago and Illinois Midland	5	< .1
Totals	45,492	100.0

(a) Private railroad

Source: Illinois Dept. of Mines and Minerals, 1979 Annual Coal, Oil, and Gas Report, May 1980, Table 11 [16].

Table 8.13

Distribution of Illinois Coal to Electric Utilities by State and Primary Transport Mode, 1980

(Thousands of tons)

State	Total	Rail	River	Great Lakes	Truck	Tramway, Conveyor, Slurry Pipeline	Tidewater Piers, Coastal Ports
Illinois	18,700	9,658	4,730	--	2397	1915	--
Indiana	7,616	7,591	--	--	25	--	--
Michigan	590	296	--	294	--	--	--
Wisconsin	2,805	2,323	481	1	--	--	--
Iowa	1,644	735	773	--	136	--	--
Kansas	81	81	--	--	--	--	--
Minnesota	723	204	519	--	--	--	--
Missouri	12,649	9,911	2,728	--	11	--	--
Florida	1,513	--	1,513	--	--	--	--
Georgia	2,457	--	2,457	--	--	--	--
Alabama	2,480	11	2,469	--	--	--	--
Kentucky	222	222	--	--	--	--	--
Mississippi	473	17	455	--	--	--	--
Tennessee	519	122	397	--	--	--	--
Louisiana	233	--	60	--	--	--	174
Total	52,705	31,171	16,582	295	2569	1915	174

Source: DOE/EIA, Coal Distribution: January - December 1980, April 7, 1981, Table 9 [36].

There are several things to observe about the above tables. First, for shipment of Illinois coal outside of the state, the tables indicate that the railroads are the exclusive carriers only to states that are contiguous to Illinois or nearby neighbors. Electric utilities in these states consume the bulk of Illinois coal; but the distances that the coal is transported is relatively short.

Second, shipments to southeastern utilities are carried mainly by barge. But, it can again be inferred that the railroads are providing a feeder service to the major barge terminals for movements to the Southeast. Since the DOE figures are not given in ton-miles, it is difficult to assess exactly the importance of railroads versus barges in shipments to the Southeast. The summary Table 8.14 below must thus be read with some caution. With the shipped distances omitted, it may be possible that barge ton-miles exceeded rail ton-miles in shipments of coal leaving the state.

Third, although somewhat significant within the state, movement of Illinois coal by truck to destinations outside of the state is insignificant. The overall ton-miles for this mode are small.

8.2.2 Delivered Coal Prices

Table 8.15 above gives the delivered price per ton on Illinois coal to electric utilities in the 13 states of largest use. Most of this coal was sold under long-term contract; less than 10 percent was purchased on the spot market. The coal varied in quality having an average heat value (Btu/lb.) ranging from 10,437 to 12,052, average sulfur content (percent/unit weight) ranging between 2.14 percent and 3.22 percent, and average ash content (percent/unit weight) ranging from 9.1 percent to 16.9 percent. The coal

Table 8.14

Primary Transport Modes of Illinois Coal to Electric Utilities Outside of Illinois

Mode	Percentage of Total Tonnage Shipped
Rail	63.3
River	34.9
Great Lakes	0.9
Truck	0.5
Tidewater Piers, Coastal Ports	0.5
Total	100.1[a]

[a] Total does not sum to 100.0 due to independent rounding.

Source: Table 8.13

Table 8.15

Average Delivered Price of Illinois Coal - 1979

State of Destination	$/ton
Illinois	24.72
Missouri	19.92
Indiana	24.60
Wisconsin	30.05
Iowa	28.63
Alabama	28.74
Georgia	29.11
Florida	39.40
Michigan	33.48
Minnesota	32.29
Kentucky	25.90
Tennessee	30.95
Mississippi	24.71

Source: DOE/EIA, Cost and Quality of Fuels for Electric Utility Plants - 1979, June 1980, Table 4 [39].

quality, presence of long-term contracts, and transport distances and modes contribute to the variance in delivered prices ranging from an average of $19.92/ton for Missouri users and to a high of $39.40/ton for Florida users.

8.2.3 Transportation Service Characteristics

From a survey of case studies of electric utility operation and fuel acquisition and descriptions of coal movements, a number of potential problems present themselves which may interrupt regular fuel transport service.

1. frozen inland waterways prevent barge traffic
2. small/congested locks restrict barge traffic -- upper Mississippi, Ohio, and Tennessee Rivers
3. coal freezing during winter prevents unloading at plant
4. car/locomotive shortages experienced by railroads
5. irregular arrival rates of unit trains at mines, docks, and plants

8.2.4 Comparative Transportation Mode Costs

In this section the total costs of providing long-distance coal transport by different modes will be compared. Since this study focuses upon long-distance and high volume coal movement, the competing modes are restricted to railroad, barge, and slurry pipeline. Any cost comparison of this type is subject to a number of uncertainties. The comparison with slurry pipelines involves comparing the existing modes with one that has a feasible technology but whose physical plant is not in place. Projection of capital cost and operating costs for a hypothetical pipeline between two points is thus subject to uncertainty. Confounding this uncertainty are several

unknowns including estimates of future volumes of demand for coal transport, interest rate, inflation rate, fuel prices, environmental regulations, regulatory restrictions and taxes. All add to the margin of error in the cost forecast.

The following tables give estimates in 1979 prices of both the fixed capital costs and annual operating costs for the transport of a uniform coal product over 1500 miles. The amount of coal transported is assumed to be 50 million tons per year. Breaking the costs down into their fixed and variable components allows comparison of transport costs of dedicated unit train, barge and pipeline. The costs estimates are based upon a hypothetical pipeline supplying Alabama, Florida, and Georgia from the Illinois-Kentucky-West Virginia coal regions. The other modes were not assumed to follow the route of the pipeline but to deliver the same amount of coal. Costs are based upon previous studies, or where figures were not available, upon the cost experience of constructing the Black Mesa coal slurry pipeline.

Tables 8.16-18 illustrate the relative operating costs of dedicated unit trains, coal slurry pipelines and barges. These comparisons depend heavily on certain assumptions, and the margin of error is large. For unit trains it is extremely difficult to assess the amount of maintenance specifically as a consequence of unit train coal traffic. In Table 8.17 we have attempted to construct a range of the value. The bottom end (zero) represents the extreme lower bound, in which coal traffic imposes no extra maintenance costs on the system. We have used this bound because, even where railroads report maintenance costs, they are aggregated over all types of commodities, so that any particular allocation to coal would be at best arbitrary. The _Report to the 1980 Florida Legislature_ [7, p. 3-3] indicates that the Louisville and Nashville Railroad, the most probable carrier of Illinois coal to the

Table 8.16

Annual Operating and Capital Costs of Slurry Pipeline

(1979 prices, 50 MMTY throughput, 38" diameter, 1500 miles)

I. Operating Cost[a] (million dollars)	
A. Slurry Prep - two plants	
1. General Administration	1.5
2. Maintenance and Supplies	4.0
3. Labor	4.6
4. Fuel	10.4
	20.5
B. Slurry Transport - 20 Pumping Stations	
1. General Administration	2.0
2. Maintenance and Supplies	9.0
3. Labor	4.0
4. Fuel	100.0
	115.0
C. Dewatering and Distribution - 10 plants	
1. General Administration	4.0
2. Maintenance and Supplies	8.5
3. Labor	8.5
4. Fuel	16.5
5. Flocculants	11.5
	49.0
Total Operating Costs	184.5
II. Capital Costs	
A. Slurry Preparation Facilities - 2 plants (118.9m each, 25 MMTY capacity)	237.8
B. Pipeline Construction - 1500 miles (1143.85m per 1000 miles)	1715.8
C. Dewatering Facilities - 10 plants (16.8m each, 5 MMTY capacity)	165.0
Total Capital Costs	2121.6

(a) Assumes negligible water costs.

Sources: 1. Report to the 1980 Florida Legislature, Coal Slurry Pipeline Study Committee, Feb. 1980, pp. 5-8, 5-9 [7].

2. Rieber and Soo, Comparative Coal Transportation Costs: An Economic and Engineering Analysis of Truck, Belt, Rail, Barge, and Coal Slurry and Pneumatic Pipelines - Volume 3 [23].

Table 8.17

Annual Operating and Capital Costs for Unit Train
(1979 prices, 50 MMTY tonnage, 1500 miles trackage)

I. Operating Cost (million dollars)	
A. Loading Facilities - 2 plants	
1. Facility Operating and Maintenance	5.1
2. Trackage	0.2
	5.3
B. Rolling Stock and Maintenance	
1. Labor	66.6
2. Hopper Cars ($.04/mile)	30.0
3. Locomotives ($.53/mile)	31.0
4. Caboose ($.02/mile)	0.2
5. Supplies	5.5
6. Fuel	65.5
	198.8
C. Unloading Facilities - 10 plants	
1. Facility Operation and Maintenance	11.1
2. Trackage	0.2
	11.3
D. Track Maintenance	Not known[a]
Total Operating Costs	215.4 + track maintenance
II. Capital Costs	
A. Loading Facilities - 2 plants (62.5m each, 25 MMTY capacity)	125.0
B. Tracks to Service Loading Facility	10.9
C. Rolling Stock	
1. Locomotives (.65m each)	213.2
2. Hopper Cars (.04m each)	246.0
3. Cabooses (.05m each)	4.1
	463.3
D. New and Upgraded Track	
1. New Track (75 mi. @ 2.56/mi.)	192.0
2. Upgraded Track (600 mi. @ .37m/mi)	222.0
	414.0
E. Unloading Facilities - 10 plants (21.78m each/5 MMTY capacity)	217.8
F. Track to Service Unloading Facility	12.1
Total Capital Costs	1243.1

(a) See text for discussion of Seabord Coast Line maintenance expenditures.

Source: Report to the 1980 Florida Legislature [7].

Table 8.18

Annual Operating and Capital Cost for Barge

(1979 prices, 50 MMTY tonnage, 1500 miles)

I.	Operating Costs (million dollars)		
	A.	Loading Facility Operation and Maintenance	22.4
	B.	Unloading Facility Operation and Maintenance	26.8
	C.	Line Haul Costs	305.3
	D.	Maintenance for Waterways	15.0
	E.	Transloading (New Orleans)	49.2
		Total Operating Costs	418.7
II.	Capital Costs[a]		
	A.	Loading Facilities - 5 plants (17.66m each, 10 MMTY capacity)	88.3
	B.	Unloading Facilities - 5 plants (17.66m each, 10 MMTY capacity)	88.3
	C.	Line Haul Equipment	
		1. Barges (410 units @ .225M)	92.3
		2. Tow Boats (14 units @ 3.2M)	44.8
		Total Capital Costs	313.7

(a) Derived from cost information described in [7, Chapter IV].

Source: Report to the 1980 Florida Legislature, [7].

Southeast, spent an average of $7,189 per mile for track maintenance in Florida, whereas in the same year it spent about $13,000 per track mile on their whole system. These figures provide no unambiguous basis for attributing any specific amount of costs to coal.

With respect to maintenance costs more directly related to coal, according to the same report:

> "The Seabord Coast Line has predicted that shipment of an additional five million tons per year of coal to Tampa would require an additional maintenance cost of $700,000. To Lakeland the cost would be $600,000, and Crystal River $500,000 per year. However, it should be understood that this is based on the use of a common track (over part of the route) . . .
>
> "For delivery to a fourth destination, Gainesville, . . . The additional cost per year for hauling an additional 0.66 million tons of coal would be $6,250 per mile for 105 miles. These maintenance costs may be reduced at the expense of increased capital cost, by installing heavier continuous welded rail. This has been done over most of the railroad's mainline."

The latter figure of $6250 per mile for 0.66 million tons is no doubt a figure very much too large to rely on for average maintenance costs due to coal movements, since it is obviously applied to way and structure not designed to handle coal. (Applied blindly, in a linear fashion to 50 million tons of coal over a 1500 mile route, it would suggest an annual maintenance cost of over 700 million dollars.) Nevertheless, Seaboard Coast Line figures do suggest that maintenance costs due to frequent unit train coal movements might make the total operating costs for railroads, reported in Table 8-17 as $215.4 million, much larger, even if only a small fraction of the $700 million figure mentioned above were appropriate for a system adequately designed to accommodate unit trains.

The problem of railroad track maintenence thus means that the annual variable cost associated with unit train movement is likely to be significantly higher than the $215.4 million suggested in the report to the

State of Florida. We have indicated this in Tables 8-19 and 8-20.

The costs for barge and pipeline movements are also understated in the report to the State of Florida, but for a different reason. The data in that report do not reflect the fact that for those modes a user must somehow get the coal from the mine to the barge or pipeline terminal. These feeder costs can be significant. For example, if the cost of feeder movements is $2.50 per ton, as is not atypical in Illinois, then the feeder costs for moving 50 million tons would be $125 million. We have indicated this omission, which constitutes an actual cost to the user of the mode, in Tables 8-19 and 8-20. It is not obvious whether the feeder costs are greater than or less than railway maintenance costs, primarily because of the very great uncertainty about the latter.

In addition, relative mode cost comparisons are difficult because it is impossible for a 1500 mile haul by rail or barge on existing track or waterway to serve the same number of utilities as the slurry pipeline which is tailored to that very purpose. To serve the group of 10 utilities also serviced by its proposed Coalstream pipeline for example, Continental Group estimates that a minimum of 2705 miles of existing Family Line track would be needed. For barge transport using the Mississippi River and Gulf Intercoastal Waterway an average haul of 1700 to 1800 miles is needed to serve the nearest three plants on the Gulf of Mexico in Florida; see [7, Appendix]. Thus, the question of circuity is an important one. It is considered in more detail in Chapter 9.

Comparison of the capital cost estimates is quite difficult for reasons pursued further in Chapter 9. For the present, we simply note that Table 8.19 indicates that slurry pipelines possess significantly higher capital costs than railroads or barges.

Table 8.19

Summary of Operating and Capital Costs by Mode

(1979 prices, 50 MMTY throughput, 1500 mi. haul)

(Millions of dollars)

Mode	Annual Variable Costs	Capital Costs
Slurry Pipeline	184.5 + feeder cost	2121.6
Unit Train	215.4 + track maintenance	1243.1
Barge	418.7 + feeder cost	313.7

Source: Tables 8.16, 8.17, 8.18.

Table 8.20 gives the breakdown of total annualized costs of pipeline and unit train transport by major variable and fixed cost categories. Barges are omitted because of the difficulty in allocating their costs among these more detailed categories. The table illustrates, among other things, that the degree of labor intensity of unit train versus pipeline transport, and the proportion of fixed to variable costs incurred by each mode. Slurry pipeline proponents often cite the discrepancy between a pipeline and unit train labor costs, suggesting that as a result of this difference rail costs will be more closely indexed to the inflation rate. However, if we make the more reasonable assumption that both labor and energy costs are subject to approximately the same rate of inflation, this argument is far less compelling. Even if all variable costs are subject to inflation, it is not clear which mode's total transport costs are lower over time.

An assortment of coal slurry pipeline cost studies have been published since 1974. The following table summarizes some of these studies. Other notable studies include: Bechtel [3], Souder, et al. [29], and Reiber and Soo [23], but these are more difficult to neatly summarize because each determines a contingent cost range estimate which depends upon a broad set of technological, environmental, and economic factors.

In Table 8.21 cost estimates range from 2.09 to 0.40 cents per ton-mile, depending upon assumed distance and throughput. But whether the costs are even roughly comparable is uncertain because all of the assumptions necessary to determine a point estimate are not consistently mentioned. Omitted are the assumed pipe diameter, whether or not water costs or gathering and distribution costs are included, the size and number of terminal facilities needed, and the assumptions used to derive annual capital costs including life of plant, interest, depreciation and tax rates.

Table 8.20

Coal Transportation Costs, Annualized by Mode
(1979 prices, millions of dollars)

Cost Category	Pipeline	Unit Train
A. Variable Cost		
1. Energy	126.9	65.5
2. Labor	17.1	149.5
3. Maintenance/ Supplies	21.5	
4. Other	19.0	.4
B. Fixed Costs[a]	265.2	155.4
Total Annualized Costs	449.7 + feeder	370.8 + track maintenance

Notes: (a) Annualizing factor (0.125) includes 10 percent return on investment and 0.025 depreciation (40 year life).

Source: Tables 8.16, 8.17, and 8.18.

Table 8.21

Previous Coal Slurry Pipeline Cost Estimates
(Cost in cents per ton-mile)

1. University of Illinois - Center for Advanced Computation, 1975

Distance	Throughput (million tons per year) 25 MMTY
300 miles	.95 ¢/ton-mile
700	.76
1040	.69

Assumed debt to equity ratio - 50:50

2. Bureau of Mines, 1975

Distance	Throughput 9.1	18.2	25.0
453	1.50	1.44	--
574	1.36	1.35	--
1000	--	--	.81
1020	1.01	.94	--

Assumed debt to equity ratio - 100:0

3. EBASCO, 1975

Distance	Throughput 4.5	9.0	18.0	25.0
500	1.73	1.73	1.86	1.90
900	2.04	1.39	1.54	1.47
1500	1.70	1.23	1.43	1.22
Pipe Diameter	18"	24"	34"	40"

Assumed debt to equity ratio - 80:20

4. Canadian Transport Council, 1974

Distance	Throughput 2	4	6	8	10	15
1200	2.09	1.55	1.28	1.06	1.0	.86

Assumed debt to equity ratio - 75:25

5. Brown and Root, Inc., 1975

Distance	Throughput 25	40
1260	1.00	.90

6. West Virginia University, 1975

Distance	Throughput 10	20	30
500	1.28	.90	.80
1000	.98	.69	.60
1500	.87	.62	.57

Assumed debt to equity ratio - 75:25

7. ESTI, 1975

Distance	Throughput 10	20	30
500	1.0	.78	.68
1000	.75	.58	.49
1500	.69	.49	.40

(38" pipeline assumed)

Source: F. E. Armbruster and B. J. Candela, "Research Analysis of Factor Affecting Transportation of Coal by Rail and Slurry Pipeline," Hudson Institute, HI-2409-RR, April 1976 [1].

8.2.5 Scale Economies

Relevant to assessing the costs of coal transport by mode is the presence or absence of scale economies. Coal slurry pipelines are characterized by two different types of scale economies: throughput and distance. Since the slurry transport system is comprised primarily of pipelines, the well-known two-thirds rule of scale up is applicable. In particular, since the carrying capacity of a pipeline increases with the square of the radius, the fixed costs of an increase in scale rise by approximately that scale increased to the two-thirds power. Thus, average costs decline as pipeline throughput is increased. In addition, since many of the fixed costs of pipeline transport are concentrated in the slurry preparation and dewatering facilities, average costs of transport decrease with distance as well because a significant proportion of fixed cost is distance-independent. Table 8.21 contains costs estimates illustrating these two types of scale economies.

Railroads also experience scale economies as throughput increases. Sometimes this is referred to as economies of density. Comparing the magnitude of these scale economies with those of slurry pipelines, however, is difficult because of the uncertainty of coal pipeline cost estimates.

Reiber and Soo [23] suggest that pipeline throughput economies are offset by the high risk of blackout associated with large diameter pipelines. Since electric utilities usually stockpile sizeable amounts of fuel, however, the risk of a blackout due to breakage seems small, and may not justify the sacrifice of available throughput economies.

8.2.6 Factors Influencing Coal Transports Costs -- Summary

As pointed out above, a definitive cost comparison between coal slurry pipelines and any competing transport mode is difficult due to the uncertainties and variabilities associated with slurry pipeline transport cost estimates. Nearly all comparative cost analyses, however, seem to agree upon two points with respect to slurry transport costs. First, over long distances coal slurry pipelines are less costly than truck and conveyer belts. Second, as transport distance increases, unit train total costs rise faster than slurry pipeline total costs and at some point exceed them. This crossover point on the average varies between 800 and 1200 miles.

A number of important factors which bear upon the relative costs of coal transport by barge and railroad versus pipeline can be identified. We are not asserting that these factors are actually present; rather, Table 8.22 indicates whether the factor, if present, may favor the proposed Coalstream pipeline. Three of these factors in particular are present in the case of the proposed Coalstream pipeline. They are: high annual throughput, long transport distance, and abundant water supplies. Other factors will be discussed in the following chapter.

Table 8.22

Principal Factors Affecting Comparative Coal Transport Costs

Factor		Condition Favorable to Florida Pipeline	Reason
(1)	High annual throughput of coal.	yes	Source of scale economies
(2)	Long transport distance	yes	Source of significant sca economies.
(3)	High expected inflation rate	?	Increases cost of more la energy intensive modes.
(4)	Large and closely-spaced mines	yes	Reduces gathering facilit costs.
(5)	Large utilities closely-spaced	yes	Reduces distribution costs and number of spurs.
(6)	Rough terrain and excavation difficulty	?	Raises construction/operation costs of mode.
(7)	Plentiful water near origin	yes	Reduces operation/construc tion costs of pipeline.
(8)	Higher relative cost of diesel fuel to electricity	yes	Raises relative operation costs of railroad and barg
(9)	Significant track circuity and poor track conditions	yes	Increases railroad operati maintenance costs.
(10)	Presence of navigable waterways	no	Increases circuity of competing barge mode.
(11)	Harsh climate of transport region	?	Raises construction/operat costs of pipeline and unit train; reduces barge viabi
(12)	Significant river/lock congestion	yes	Raises operation costs of barge.
(13)	Presence of rate regulation	?	Affects economic viability of modes (see Chapter Four

CHAPTER 9

POTENTIAL IMPACTS

9.1 Introduction

In this chapter we will attempt to assess some of the potential economic impacts of coal slurry transport if eminent domain legislation is passed. Particular emphasis is placed on the Coalstream pipeline proposal and on possible impacts relating to the State of Illinois.

As a point of departure, we will assume that federal eminent domain legislation passes. This is not done to prejudge the result of existing debates, for that outcome is uncertain. Rather, we make that assumption because, without such legislation, it is far less likely that an Illinois to Florida pipeline would in fact be constructed.

We begin by discussing in more detail the nature of intermodal competition between rail, barge, and coal slurry pipelines, with an emphasis on the pricing standards that have been used by regulators. Some of the effects of the Staggers Act on coal slurry pipelines are then considered. This discussion will indicate what kinds of cost comparisons are relevant to

an assessment of the nature of intermodal competition resulting from the passage of eminent domain legislation. We then draw on our preliminary analysis of costs in Chapter 7 to see whether the coal slurry pipeline is likely to be competitive. We will then address the issues of source water, and will indicate why that does not appear to be a major problem. Finally, we will attempt to indicate the way in which a coal slurry pipeline will affect the demand for Illinois coal movements to the Southeast. This latter exercise logically connects each of the issues discussed in this chapter.

9.2 Intermodal Competition and Fully Distributed Costs

Historically, the introduction of a new mode of transportation into interstate markets has often created interesting and difficult problems for regulators. The development of coal slurry pipelines is likely to do the same. One of the principal sources of the regulatory dilemma that may unfold is that railroads are multiproduct firms, while pipelines usually operate as single product firms. We adopt this characterization in our analysis. The Coalstream pipeline as proposed will carry only coal slurry. Yet coal is only one of many commodities carried by railroads, and for the matter, by barges.

The nature of the dilemma can be illustrated with an example. Suppose we are interested in the transportation of coal from point A to point B, and that both a coal slurry pipeline and a railroad line presently exist to provide that service. The pipeline has associated with it some large fixed costs (i.e., costs that do not vary with the level of output) from the construction of the pipeline. It also incurs some variable costs (i.e., costs that do change with the level of output) including power for pumping and labor, among other things. If the pipeline is to earn a normal return on its investment

without a government subsidy, then its coal transport rates must generate revenues that are large enough to cover both variable costs and amortized fixed costs.

Now let us contrast this with the cost situation of the railroad. The railroad hauls many kinds of commodities. In its operation, it too incurs some variable costs, including for example, fuel and labor expenses. It also incurs significant fixed costs, including much of the investment in yards and way and structure.

In addition to the distinction between fixed and variable costs, for the railroad there is an alternative method of categorizing costs. Some of the costs incurred by the railroad can be unambiguously and directly attirbuted to the shipment of an individual commodity. For example, passenger car costs can unambiguously be assigned to passenger service. Certain kinds of freight cars can be assigned to particular types of freight service without question. These costs are usually referred to as directly attributable (or traceable) costs.

However, many of the costs incurred in railroad operations cannot be unambiguously attributed to the provision of any particular type of commodity transport. For example, railroad track and roadbed are used in the transport of all the commodities that pass over the track. Thus, the costs of railroad track are shared among many commodities, rather than being directly attributable to any specific commodity. These kinds of shared costs are usually referred to as common costs.

Now we can describe the heart of the regulatory dilemma. Suppose we are interested in the allowable transport rates for a particular commodity, in this case coal. For the pipeline, as we have described above, the coal transport rate must generate revenues sufficient to cover all of the costs

(both fixed and variable) incurred by the pipeline firm. In particular, a pipeline rate equal to average variable cost would not allow the firm to break even, since such a rate would fail to generate revenues to cover the fixed costs of the enterprise.

The case of the railroad rates is more complex. Historically, the Interstate Commerce Commission has used a concept of fully distributed costs for ratemaking purposes for individual commodities. This procedure begins by allocating all of the directly attributable costs incurred in the provision of a particular type of service to that commodity. So, for example, revenues from coal transport would be required to cover at least all of the costs that are directly attributable to coal transport.

However, if the transport rate for each commodity were set so that only the attributable costs were covered, then none of the common costs (and these are huge in railroad operations) would be covered. So the ICC has typically allocated a portion of these common costs to individual commodities. The basic idea is that all of the common costs should be allocated somewhere (hence the names "fully distributed costs," or "fully allocated costs") for ratemaking purposes. In sum, fully distributed cost pricing as practiced by the ICC would require that the tariff for an individual commodity would generate revenues sufficiently large to cover not only all of the directly attributable costs, but also the designated portion of common costs.

The nature of the intermodal competition that could be expected under fully distributed cost pricing is thus dependent on the relationship between the pipeline tariff and the fully distributed cost rail tariff. For example, if the rail transport coal rate based on fully distributed costs greatly exceeds the pipeline tariff, then the railroad will attract little or none of the coal transportation market demand. This, in turn, obviously depends on

the extent to which the ICC would prescribe an allocation of common costs to coal service.

A basic criticism of fully distributed cost pricing, and one that emerges once again here, is that it is inherently arbitrary, since there are literally an infinite number of ways of allocating common costs. For example, one could allocate common costs to individual services in proportion to directly attributable costs. Thus if service 1 has twice has twice the attributable costs of service 2, then service 1 would be required to cover a portion of common costs twice as large as that for service 2. Or, one could allocate common costs in proportion to gross revenues. Still another way to allocate common costs (and this is the one used most often by the ICC historically) is to distribute them in proportion to the number of ton-miles of each commodity.

A detailed critique of these mechanisms is beyond the scope of the present investigation. So is an analysis of the way such rates ought to be set if the goal is to maximize the economic efficiency with which resources are allocated. Nevertheless, the current discussion serves a valuable purpose. It indicates that the profitability of both modes, railroads and pipelines, will depend on the pricing method used. If railroads must set high prices for coal transport, then pipelines will have a better chance of survival. This is exactly the nature of the intermodal problem that has arisen repeatedly over the decades in other contexts, such as in markets in which railroads and motor carriers have competed.

9.3 The Staggers Act: Changing Ground Rules for Intermodal Competition

Over the past five years two major pieces of legislation have been enacted which change the rules of intermodal competition. The first was the

Railroad Revitalization and Regulatory Reform Act of 1976, commonly referred to as the "4-R" or "Quad-R" Act. This statute created some rate flexibility for railroads in their pricing of transport services. Over time the Act allows railroad rates for for many commodities to vary, at the pleasure of the railroads, within certain "zones of reasonableness." Thus, in 1976 the statutory basis was laid for some departure from strict fully distributed cost pricing standards as had been practiced by the ICC. Still, the Act was to be administered by the ICC, and that agency possessed considerable discretionary power in determining conditions under which the "zones of reasonableness" flexibility would be allowed.

More recently rail rate flexibilities have been increased under the Staggers Act of 1980. Basically, the new law allows railroad rates to be unregulated in transport markets which are not "dominant markets." A dominant transport market is one in which a single rail carrier has more than a 70 percent share of the railroad transport in that market. If the share of the railroad market exceeds 70 percent for any railroad, then the ICC can intervene to regulate rail prices directly, particularly if the dominant rail carrier seeks to set a rate in excess of 160 percent of average variable cost (this upper bound is scheduled to increase slightly over time).

How does this discussion relate to intermodal competition involving coal slurry pipelines? While it is no doubt too early to tell just how the Staggers Act will be implemented in detail, the major implications are becoming clear. The Staggers Act would retain direct rate regulation in dominant markets, restricting its attention to <u>maximum</u> tariffs rather than minimum tariffs. Thus, although the issue of what constitutes a dominant market may take some time to resolve, it is largely irrelevant to the intermodal competition which we focus on in this study. Minimum rates under

the Staggers Act could be so low for a particular commodity that the revenues generated would cover virtually <u>none</u> of the common costs.

Two observations follow directly from this discussion. First, this explains why railroads are so concerned with the possible loss of coal business to the pipelines. Railroads have been earning rates of return on investment much below market rates throughout the 1960's and 1970's, and that trend has continued in the present decade. Railroads apparently have hoped to use greater rate freedom in coal markets to raise revenues, and consequently raise their return on investment to normal levels. The advent of competition from coal slurry pipelines may jeopardize their ability to raise coal rates, and this is reflected repeatedly in the Congressional hearings on slurry pipelines.

The second point that emerges here is the nature of the cost comparison that is relevant to an assessment of whether pipelines can compete successfully with railroads. The costs that are important here are: (1) the attributable costs for coal service for railroads, since if total coal revenues are below total attributable coal costs, railroad profits would increase by dropping the coal service, and (2) total costs, including amortized fixed costs, for the pipeline, since total revenues must exceed total costs in order for the pipeline to be economically viable.

9.4 Pipeline Viability

The previous section has provided a rationale for cost comparisons that are relevant to a determination of pipeline viability. In this section, we employ information reported in Chapter 8 to draw some inferences on the nature of these costs. Some summary data, based on studies performed by a number of

researchers, appear in Tables 8.16 through 8.21. The figures presented in Table 8.19 provide an appropriate point of departure for our comparisons here. First, we observe that for all three modes (pipeline, unit train, barge) costs are based upon the same annual throughput over 1500 mile hauls. We defer a discussion of route circuity for the present.

For the purposes of performing crude cost comparisons, we assume that the pipeline has a life of 40 years, while the life of a railroad's assets is between 20 and 40 years. The railroad life assumption recognizes that some items for railroads have very long lives (e.g., track), while others (say, ties and cars) have much shorter lives.

Table 8.19 states that the annual operating costs for pipeline and rail are quite comparable relative to barge operating costs. On the other hand, the capital costs associated with pipeline assets are much higher than that for railroad assets, and both are much larger than the capital costs associated with barge operations.

Let us construct an approximation of annual costs, including amortized plant costs, for the pipeline. Assuming a life of 40 years and a normal return on investment of 10 percent, then an amortization factor for pipeline plant costs would be approximately 0.125 (= 0.10 + 0.025). Thus, the equivalent annual outlay of costs for the pipeline would be 184.5 + 0.125 x 2121.6 = 450 million dollars. To this figure we would have to add feeder costs to arrive at an actual cost to users of the pipeline.

For the railroad, again assuming a normal return of 10 percent, then the amortization factor would lie between 0.125 (for assets with a 40 year life) and 0.15 (for assets with a 20 year life). Thus, the equivalent annual outlay for the attributable costs of unit coal operations would be between 371 and 402 million dollars plus track maintenance costs for coal movements. We refer

to the costs we have calculated as attributable costs since most of those capital and operating costs in Table 8.17 appear to be attributable. In particular the costs reflected in that table do not appear to contain large amounts of arbitrarily allocated common costs, as is often done with fully distributed cost pricing methodologies.

For barges, a similar calculation, including an assumption of a 10 percent normal return on investment and a life of 20 years leads to an annualized outlay of 466 million dollars for a large operation dedicated to coal transport. Again, we would have to add feeder costs to arrive at a cost to users for this mode.

We reemphasize that these are at best very crude calculations. Before drawing any inferences from the calculations, we must identify and discuss a number of caveats and uncertainties. However, even the following list will not prove exhaustive.

First, for railroad operations, it is not clear that the costs used in the calculation exactly correspond to the attributable costs of operation as defined in Section 9.2. For example, no quantitative estimate of track maintenance costs are included in Table 8.17. We know from estimates cited in Chapter 8 that track maintenance expenditures for a railroad can be substantial. Many of these expenditures will be common costs, but some may be directly attributable to the provision of coal transport. As a result, the costs in Table 8.17 may not include all of the attributable costs. At the same time it is not clear that all of the costs included in that table are actually attributable. For example, some of the new and upgraded track included in capital costs may benefit more than coal traffic, thereby perhaps being a form of common cost. Thus there could be either upward or downward biases in the data, and we are uncertain about the magnitudes involved.

A second caveat has to do with circuity. As mentioned above, the cost comparisons in Chapter 8 are for systems of 1500 miles. It is an open question as to whether this is in fact an appropriate comparison. Continental Resources Company [7] noted several objections, including the following:

> "Using a Family Lines map of existing track, a railroad system was drawn from the same two origin points over the shortest possible distance to the same ten power plant locations. A minimum of 2705 miles of rail track is required to accomplish the same transportion task as the pipeline."

In an attempt to examine the nature of circuity and assess the validity of circuity arguments, we have independently performed such an exercise. Our own findings indicate that, using primarily Family Line track, a similar total rail distribution network of approximately 2400 miles, serving 16 of the 18 utilities listed in the Betchel study [3], is necessary.

We also performed a similar check for barge transport distances from Illinois to those four of the 18 utilities (in the Bechtel study) that are located on the Florida Gulf coast: Lynn Haven, Crystal River, Big Bend, and Gannon. This distribution network includes movements down the Ohio and Mississippi Rivers, and then along the Gulf Intercoastal Waterway to Florida. The total distance for this movement was found to be 1856 miles.

We also include barge-rail combination movements from Illinois to 16 utilities in the Bechtel report (not including two in the Florida panhandle) with barge movements up the Tennessee River and rail movements to each of the utilities. Such a movement, by our estimation, would involve a total distribution system of about 2170 miles.

Why should we worry about circuity? Souder and Burt [29] have found that route circuity is the single most important factor bearing upon total rail transport costs and the second most influential cost factor for slurry

pipelines. There is little doubt that the barge and barge-rail routes discussed above are more circuitous than either direct rail or slurry pipeline routes. In fact, they are only measured for movements from Illinois to the Southeast.

There is a question as to the measurement of circuity from the standpoint of direct rail and slurry pipelines. Continental Resources has argued that "in order for the economic and net energy comparisons to be meaningful, each of the assumed transportation systems must be able to perform the same transportation task." That is why they have argued that a rail network of 2705 or more miles would be required to provide the same distribution network as the 1500 mile pipeline.

Our own conclusion is that, while direct railroad movements may involve somewhat longer routes in some cases, the extent of the circuity is overstated by comparison of 2705 (CRC estimate) or 2400 (our estimate) miles for rail versus 1500 miles for pipeline, at least for purposes of discussing profitability. Our reasoning for this conclusion is straightforward, based on the earlier discussion of the cost concepts relevant to a determination of economic viability under intermodal competition. When making a decision to provide service to a particular location, a railroad will compare the revenues received for that service with the additional costs incurred in providing that service. The costs associated with a particular movement will be determined by the actual distance travelled in that movement, and not movements to other destinations. Thus, we do observe that some rail movements may involve longer distances than pipeline movements, but for no movement will the difference between the distances involve more than a couple hundred miles.

Our reasoning also leads us to note that the conclusion would be much different if the track in question were to be newly constructed and dedicated

to coal movements. In that counterfactual case, the rail network costs would in fact be unambiguously attributable to coal movements, and the attributable costs of such movements would have been calculated to be much larger. But that is certainly not the case in the present proposal.

Another area which has drawn much attention in terms of rail-pipeline cost comparisons is the relative impact of inflation. It has sometimes been alleged that the costs incurred by pipelines are better insulated from the effects of inflation, since pipelines are more capital intensive than railroads, and a pipeline system is designed to last as long as forty years.

It is difficult to quantify the relative effects of inflation. To begin with we have already observed that the operating costs for rail and pipeline systems of a 1500 mile length are of the same order of magnitude (again, see Table 8.19). An examination of Tables 8.16 and 8.17 reveals that operating costs are dominated by fuel costs for pipelines and by fuel and labor costs for rail operations. We would be reluctant to say which set of operating costs would be escalated at a higher rate as a result of inflation.

Further, a correct cost analysis would involve a comparison of the present value of cost streams over the appropriate planning horizon. Such an analysis would express cash flows in terms of real rather than spot (inflated) dollars, so that the effects of inflation are overstated if inflated dollars are used to represent future costs. The rationale for this statement is that while inflation may double the purchase price of an asset, say, ten years from now, it will also be possible to buy that asset with inflated dollars. Thus the real expenditure on the asset, in terms of, for example 1979 dollars, may not be significantly affected by inflation. These kinds of considerations have not been handled in a systematic way in the cost comparisons we have discussed in Chapter 8.

Where does all of this leave us? First, we observe that since barge traffic has historically been quite competitive in this country, barge rates are probably quite close to the marginal costs incurred by water carriers. There is little evidence to suggest that drastic reductions in barge rates are likely to occur with the advent of a pipeline. That is why this study has focused on the potential rate reductions that railroads might offer in response to a coal slurry pipeline. Second, subject to a number of qualifications we have discussed in this section and in Chapter 8, we conclude that it may in fact be possible for a coal slurry pipeline to Florida to survive, even against a railroad pricing scheme designed to generate revenues that cover only those costs attributable to coal movements. There does not appear to be an overwhelming cost advantage for either mode. As suggested in Section 6.5, perhaps the most significant impact of the coal slurry pipeline would be to reduce coal transportation rates from maximum levels allowed under the Staggers Act (i. e., 160 percent of average variable cost) to approximately the average variable cost of railroad coal movements. We will discuss this in more quantitative detail in Section 9.6.

9.5 Water Requirements

In this report we have not dwelled at length on the water requirements issue often raised in connection with coal slurry pipelines. As a number of sources have suggested, if we were assessing the viability of a pipeline in the western part of the United States, that problem would have dominated our discussion. In the case of the Coalstream pipeline, the estimated water requirements would be about 40 cubic feet per second. The ratio of requirement to river volume can then be calculated to be 0.00052.

In its own assessment of a pipeline using Tennessee River water, the Office of Technology Assessment [32] has made a similar calculation. A proposed pipeline would require about 12000 acre-feet per year, drawing from a river flow of about 25.6 million acre-feet per year. The ratio of requirement to river volume can then be calculated to be about 0.00047. In this case the OTA concluded that water requirements would constitute no real problem for a pipeline; see [32, p. 102]. Since the ratio of requirement to river volume is of the same order of magnitude in the Coalstream pipeline case, the issue of water source adequacy does not seem to be a siginificant problem, especially if, as proposed, reservoir storage facilities are to be constructed just in case a low water level should ever occur.

9.6 Potential Impacts on Coal and Other Markets

Thus far our analysis has led us to conclude that the introduction of a coal slurry pipeline might have among its most important effects a significant effect on coal transport rates. Our investigation of the growing literature surrounding coal slurry pipelines has uncovered quite a bit of concern over comparative costs of coal transport, but relatively little in terms of transport price effects. In this section we will attempt to show what some of these price effects might be.

At the close of Section 9.4, we suggested that in response to intermodal competition from the pipelines, railroads might lower their coal tarriffs from the maximum allowed under the Staggers Act in dominant rail markets, to something approximating average variable costs. Quantitatively what does this mean? If the rates before the pipeline were built were 1.6 times as large as average variable cost, then the percentage rate reduction that might be

anticipated would be as large as (1.6-1.0)/1.6, or 37.5 percent. This follows directly from the institutional and legislative discussion developed at length earlier in this chapter.

What would this mean in terms of the delivered price of coal in Florida. Coal transportation charges have typically been no larger than 20 percent of delivered coal prices, although in some cases the figure could be a bit larger. Thus, the reduction in the delivered price of coal might very well be on the order of about 7.5 percent (0.2 x 37.5), which we use for illustrative purposes.

An additional question that might be asked is, "What effect will this price change have on the demand for coal in Florida, Alabama and Georgia, and therefore ultimately on coal purchases from Illinois producers?" We can make a very rough estimate of these effects, although we will require some strong assumptions in the process.

To begin with, a number of studies of coal demand indicate that this demand is relatively inelastic. For the purposes of our calculations, we will assume a "typical" price elasticity of demand of -0.5. The price elasticity of demand is defined as follows. Suppose the price in a market falls by x percent, and that the quantity sold therefore increases by y percent. Then the price elasticity of demand is simply the ratio of y to x.

Thus, if the price elasticity of demand is -0.5, then a 7.5 percent decrease in delivered coal price would lead to an increase in coal purchased of 3.75 percent. In other words, if the elasticity of demand for coal in Florida, Alabama, and Georgia is -0.5, and if the pipeline leads to a 7.5 percent decrease in the price of delivered coal in that region, than the quantity of coal purchased in that region can be expected to increase by about 3.75 percent.

The extent to which this might affect purchases of Illinois coal would be dependent, of course, on whether the percentage of Illinois coal purchased by utilities in Florida, Georgia, and Alabama from Illinois changes. Presently, as Table 8.7 indicates, 12.3 percent of the coal produced in Illinois and sold to electric utilities moved to those states in 1980, representing 6.45 million tons. Therefore, if the 3.75 percent increase in coal purchased in this region were to lead to a 3.75 percent increase in the electric utility demand for Illinois coal, this would have increased the demand for Illinois coal by about 0.24 million tons (0.0375 x 6.45) in 1980.

The figure of 0.24 million tons per year appears to represent a rather small fraction (0.39 percent) of the total Illinois coal production of 62.0 million tons in 1980. It might be increased if the demand for coal were more elastic than -0.5 (this is not likely given the range of observations in published research), or if intermodal competition forced a drop in rail coal tariffs of more than 37.5 percent (this is not likely since below average attributable cost pricing is unprofitable), or if coal transport comprised a larger portion of delivered coal prices than 20 percent. However, for any reasonable variations on these illustrative figures, the effects on Illinois coal production remain small. To see the extent of the robustness of this point, suppose that coal rates were 40 percent lower with pipeline competition, that the elasticity of coal demand were as large as -1.0, and that coal transport rates comprised 25 percent of delivered coal prices. These conditions are biased to yield an impact on the Illinois coal market much larger than the more reasonable assumptions above would justify, and yet even they would lead to a prediction that the increase in Illinois coal production caused by a pipeline to the Southeast would be only about 1.2 percent above the level of production that occurred without the pipeline.

Since this finding represents one of the major conclusions of this study, it is worthwhile to expand on it. For illustrative purposes, suppose that the demand for coal shipped from Illinois to electric utilities in the Southeast, without a coal slurry pipeline, increases from about 6.45 million tons in 1980 (see Table 8.7) to about 10.7 million tons in 1990. (See Table 12.2 of this report.)

What then would be the impact on the demand for Illinois coal if the slurry pipeline were built? If, as we have suggested above, the advent of the pipeline is to increase the demand for Illinois coal shipped to utilities in the Southeast by 3.75 percent, then the pipeline would raise the projected demand for those movements from 10.7 to 11.7 million tons (1.0375 x 10.7). Thus, by 1990, the calculation indicates that 0.4 million additional tons would move to utilities in the Southeast if the pipeline were built.

In closing this chapter, we would like to reiterate that many of our calculations, including the one just made, are based on a good deal of uncertainty. We have assumed no changes in the prices of alternative fuels that might be made in response to lower coal prices. And we have assumed that the producers of coal in Illinois and elsewhere do not raise their prices as they see coal transport rates drop. Nevertheless, we believe that the conclusions of this chapter do represent an interesting set of rough approximations of the kinds of effects that a coal slurry pipeline might have on coal transportation and production. A more detailed analysis of the operation of coal markets and coal transport markets would involve theoretical and statistical modeling requiring more resources and time than this project has allowed.

CHAPTER 10

CONCLUSIONS

This study has been designed to identify and assess some of the potontial economic consequences of a coal slurry pipeline from Illinois to Florida, Alabama, and Georgia. We have described the nature of coal slurry pipeline technology, and the status of the proposed Coalstream pipeline. The major forces and issues that have surrounded this hotly contested venture were also identified.

In attempting to analyze the potential consequences of the pipeline, we have found it necessary to describe the market for Illinois coal along with the movements of Illinois coal by mode to out-of-state users. In the course of this work we have examined and summarized a number of comparative cost studies focusing on the transportation of coal by alternative modes.

Finally, in Chapter 9 information on market operations, relative costs, legislative and regulatory practices, and economic incentives were integrated to draw a number of conclusions about the potential impacts of a slurry pipeline on coal markets, particularly as they might affect the Illinois region. Although our findings are too numerous to enumerate in any great detail here, we will describe those that appear to be most important.

1. Given the large estimated distance and throughput, the Coalstream coal slurry pipeline may be able to transport coal at a per unit cost camparable to the average attributable costs of coal transport by unit train over direct rail routes to the Southeast.

2. Adequate water supplies for the pipeline, often a problem in the West, appear to exist for the Coalstream pipeline. We discovered no obvious adverse affects on the Illinois region. No detrimental enviroment consequences are apparent.

3. Approximately 12.3 percent of the coal produced in Illinois and sold to electric utilities was sold to utilities in Georgia, Florida, and Alabama in 1980. This is the market that Illinois producers might hope to expand with a slurry pipeline.

4. Competition introduced by the coal slurry pipeline could lower the rail transport rate for coal by as much as 35 to 40 percent. This would occur as railroads move their rates away from the maximum permitted under the Staggers Act of 1980 with no intermodal competition from coal attributable costs for rail coal movements in order to compete with coal slurry pipelines.

5. As railroads lose the incentive to charge the maximum rate under the Staggers Act upon introduction of coal slurry pipeline, they will be forced to generate revenues to cover their common costs of production from other commodity movements if they are to earn a normal return on investment. Thus other commodity rates may rise. The advent of coal

slurry pipeline technology will make the railroads' efforts to earn a normal return on investment even more difficult.

6. Assuming that coal transport rates comprise approximately 20 percent of delivered coal costs, a reduction in coal transport rates of 37.5 percent could lead to a reduction in the price of delivered coal in the Southeast of as much as 7.5 percent. This assumes that coal suppliers do not change their prices.

7. Assuming typical values for the price elasticity of coal demand, coal transport costs as a percentage of delivered coal prices, and transport rate decreases due to pipeline competition, total production of Illinois coal will probably be increased by no more than 1 percent if a coal slurry pipeline is built relative to the level of production that would occur if no pipeline were built. Further, a coal slurry pipeline will probably increase the movements from Illinois to the Southeast by no more than 4 percent relative to the level that would be observed if no pipeline were built.

8. We would expect that as the rates for direct rail transportation fall in response to a coal slurry pipeline, much of the traffic currently moving by barge and barge-rail combination to the Southeast will be diverted to direct rail and coal slurry pipeline routes. Therefore, railroad movements of coal in Illinois from mines to barge terminals will most likely become movements to the pipeline origin or remain on rail for interstate carriage to the Southeast.

We reiterate that many of these conclusions, especially the quantitative ones, are subject to the uncertainties that often accompany assessments of the effects of new technologies, especially since the potential effects on transport rates are more than marginal. A more detailed assessment of these effects would require theoretical and statistical modelling that was beyond our modest capabilities under the present project.

PART III

AN ANALYSIS OF PAST AND PLANNED USAGE OF COAL BY ELECTRIC UTILITIES WITH RESPECT TO ILLINOIS

by

David E. Boyce

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CHAPTER 11

INTRODUCTION

11.1 Background

As noted in Part II of this report, Illinois coal production experienced a substantial decline during the 1970's. The extent of the decline is difficult to judge from aggregate production totals because of distortions caused by strikes in some odd-numbered years. Nevertheless, it is generally understood that the electric-utility industry reduced its usage of the high-sulfur coal typically produced in Illinois in order to comply with the standards of the Federal Clean Air Act of 1970. Utilities in Illinois and nearby states generally substituted low-sulfur Western coal in order to meet the Federal sulfur-dioxide standards. Utilities in the East and Southeast substituted oil and gas for coal, in order to meet standards pertaining to particulate matter. Nuclear energy, which appeared to offer a longer-term, cost-effective solution to meeting the Federal standards, received increased emphasis in utility industry planning, especially in Illinois.

The determinants of the choice of fuel for electric generation, however, are complex and constantly evolving. The Clean Air Act of 1970 was, in retrospect, one of a series of exogenous forces affecting the electric utility industry during the decade. The Arab oil embargo of 1973 and the ensuing sharp increases in the price of imported oil, followed by increases in the prices of domestic oil, gas and coal, again altered the economics of power generation. Subsequently, the Clean Air Act of 1977 extended some regulations pertaining to high-sulfur coal to all coal. Moreover, the application of these regulations to specific electric generating stations varies according to the air quality in the general vicinity of the generating station.

In this highly complex economic and regulatory environment, it is difficult, if not impossible, to understand and predict the resultant overall effect on a major coal-producing state such as Illinois. An alternative approach to such an analysis is simply to observe the responses of the utility industry in terms of their current fuel purchases and their plans for fuel purchases five and ten years hence. Since these current and planned coal purchases must be reported to the Federal Energy Regulatory Commission by law, and because electric utilities increasingly engage in long-term contracts for their fuel supply, the aggregate of the utilities' plans may be regarded as providing a reasonably accurate indication of future events.

In mid-1979, a research team at the University of Illinois at Urbana-Champaign undertook a study of the future outlook for consumption of Illinois-produced coal by the U.S. utility industry and the future sources of coal consumed by utilities located in Illinois. The resulting report [4] portrayed a decidedly optimistic outlook for usage of Illinois-produced coal. The survey conducted in mid-79 indicated a planned increase by utilities of Illinois-produced coal from 49.2 million tons in 1977 to 60.3 tons by 1982 and

67.8 million tons by 1987. These increases reflected plans by electric utilities in Illinois and adjacent states to use high sulfur Illinois coal in generating stations equipped with flue gas scrubbers constructed since 1976. The survey also revealed a major new market for Illinois coal in the Southeast, principally in Florida and Georgia. Several utilities in these states had identified Illinois coal as the minimum cost fuel for use in newly constructed or planned coal-fired generating stations, which were replacing oil and gas-fired plants constructed much earlier. With regard to usage of coal by Illinois utilities, the survey showed that the major shift from Illinois to Western coal that occurred in the early-70′s was nearly complete.

Although these plans of utilities in Illinois and elsewhere were generally more favorable toward use of Illinois coal than actual use in recent years, the report concluded that such plans were subject to change. Unforeseen forces in the 1980′s could disrupt this pattern of usage, just as they did the highly favorable position that Illinois coal producers enjoyed in the 1960′s. The research report recommended that the survey be updated periodically for this reason. A partial update was undertaken in 1980, but plans beyond 1987 were not obtained. A more complete update of current usage in 1980 and planned usage for 1985 and 1990 was completed in mid-1981, and the findings conveyed to the Illinois Department of Transportation as well as the Illinois Department of Energy and Natural Resources.

The findings of the 1981 survey are reported in Part III of this report. Chapter 11 describes the survey procedure and lists the utilities contacted. Chapter 12 reports the findings and compares them with the 1977-82-87 survey. Moreover, tables pertaining to planned additions of generating capacity and recent state-to-state coal flows are updated to 1980, the most recent year for which these data are available.

11.2 Survey Approach

The 1979 survey was begun by obtaining the Steam-Electric Plant Air and Water Quality Control Data Forms (Form 67) filed with the Federal Energy Regulatory Commission (FERC) by each of the electric utility companies within the Illinois coal market region for operations in 1977. The study was limited to electric utility companies, as it was determined that they were the most significant users of Illinois coal. From these Form 67s, data were compiled for the years 1977, 1982 and 1987 on coal use by U.S. Bureau of Mines Production District. Since more detailed information as to mode and route of transportation was desired, a telephone/mail survey was undertaken. These interviews also permitted checks to be made on the accuracy of the reported and planned usage.

For the 1981 study, the data collected for 1979, and also in 1980, were used as a starting point for interviews with utilites. An expanded list of utility companies, shown in Table 11.1, was contacted by telephone, or mail when necessary, and the appropriate information relating to origin (mine site and company), destination (utility plant), mode of transportation, and the amounts of coal shipped in 1980 and planned shipments in 1985 and 1990 were obtained.

Although the group of utilities contacted has been extended, it should be noted that there may still be some utility companies using Illinois coal that have been overlooked. Through the use of the <u>1980 Keystone Coal Industry Manual</u>, however, it is possible to conclude that all major users of Illinois coal have been located.

Table 11.1

Electric Utility Companies Contacted in 1981 Study

Florida
- Florida Power
- Gulf Power
- Seminole Electric
- Florida Power & Light Co.
- Tampa Gas & Electric Co.

Georgia
- Georgia Power
- Savannah Electric Company

Illinois
- Central Illinois Light Co.
- Central Illinois Public Service
- Commonwealth Edison
- Electric Energy
- Illinois Power Co.
- Southern Illinois Power Cooperative
- Springfield Water, Light & Power
- Soyland Power

Indiana
- Hoosier Energy
- Northern Indiana Public Service
- Public Service Company of Indiana
- Indianapolis Power & Light Co.
- Richmond Power & Light Co.

Iowa
- Interstate Power
- Iowa Electric Light & Power
- Iowa - Illinois Gas & Electric
- Iowa Southern Utilities
- Muscatine Power & Water
- Iowa Public Service Co.
- Cedar Falls Municipal Utilities

Kentucky
- Henderson Muncipal Power & Light Co.
- Kentucky Utilities Co.
- Owensboro Municipal Utility Co.
- Louisville Gas and Electric Co.

Michigan
- Consumers Power
- Detroit Edison Co.
- Upper Peninsula Power Co.
- Detroit Public Lighting Dept.
- Lansing Board of Water & Light

Minnesota
- Northern States Power Co.
- Minnesota Power & Light Co.
- Rochester Public Utility Dept.
- Austin Utilities
- New Ulms City Electric

Mississippi
- Mississippi Power
- South Mississippi Electric

Missouri
- Associated Electric Cooperative, Inc.
- Kansas City Board of Public Utilities
- Missouri Public Service
- Sikeston Board of Public Utilities
- Union Electric
- Springfield City Utilities
- Empire District Electric Co.
- Central Electric Power Co.

Ohio
- Ohio Electric & Power Co.
- Cincinatti Gas & Electric Co.

Tennessee
- Tennessee Valley Authority

Wisconsin
- Dairyland Power Cooperative
- Wisconsin Electric Power
- Wisconsin Power & Light
- Wisconsin Public Service Corp.

CHAPTER 12

CURRENT AND PLANNED COAL USAGE

12.1 Present and Future Use of Illinois Coal

Electric utility demand for Illinois coal experienced a large decline in the 1970's, primarily due to the implementation of sulfur dioxide emission standards. As shown in Table 12.1, however, use of Illinois coal by the utility industry has largely recovered. The most significant reason for this recovery seems to be the installation of scrubbers on many generating stations built since 1976. Moreover, even more restrictive sulfur dioxide emission standards have been issued in recent years applying to nearly all coals, which remove the advantage enjoyed by Western coal.

The demand for Illinois coal by electric utilities is determined by both positive and negative factors. The positive factors include the large quantities of economically mined coal underlying much of the state. Moreover, Illinois' central location provides a transportation cost advantage in supplying coal to the Midwest and East. Negative factors, of course, are the high sulfur content of Illinois coal, and the increasing use of nuclear power.

Table 12.1

Changes in Past Use of Illinois Coal

(thousands of tons)

All Uses	1973	1977	1979	1977 to 1979 Net Change
Electric Utility	49,705	45,106	49,436	+4330
Coking	4,438	2,974	2,989	+15
Retail	663	239	177	-62
Other Industrial	7,736	6,033	6,208	+175
Total	61,950	54,352	58,810	+4458
Electric Utilities				
Illinois	24,091	18,432	18,867	+435
Indiana	5,331	3,791	6,843	+3052
Wisconsin	4,599	3,839	3,237	-602
Iowa	2,714	1,865	1,955	+90
Missouri	8,014	11,822	11,653	-169
Kentucky	2,923	997	464	-533
Minnesota	1,574	1,205	716	-489
Michigan	680	658	785	+127
Georgia/Florida	763	1,440	2,949	+1509
Tennessee	858	252	415	+163
Alabama/Mississippi	1,271	804	1,467	+663

Source: U. S. Department of Energy, Bituminous Coal and Lignite Distribution, Energy Information Administration, Washington, D. C., 1973, 1977, and 1979.

The data collected in this 1981 survey are summarized in Tables 12.2 and 12.3. Table 12.2 presents the current and planned shipments of coal from Illinois mines to power plants within the Illinois coal market region. Table 12.3 shows coal shipments from all sources to power plants within Illinois. Many of the planned shipments represent large contract purchases made by the utility companies.

Table 12.2 indicates that electric utilities increased their purchase of Illinois coal by 39 percent from 1977 to 1980. Some of the increase may reflect stockpiling of coal in 1980 in anticipation of a 1981 miner's strike. Most of this increase comes from large increases in demand for Illinois coal by utilities in Indiana, Missouri, Florida and Georgia. Indiana and Missouri are part of Illinois' traditional market, whereas Florida and Georgia represent a growing market in the Southeast as the U.S. begins to "wean" itself from foreign oil. Utilities' plans for 1985 and 1990 show a slight decrease in consumption. These decreases appear to be a result of increasingly restrictive emission standards, and lack of definite plans for future years.

Table 12.3 indicates that electric utilities in Illinois decreased their purchases of all coal by 7 percent from 1977 to 1980; shipments from Illinois mines and mines outside Illinois declined by roughly equal amounts. A further decrease of 9 percent is planned from 1980 to 1990. Unlike the 1977-80 period, however, use of Illinois coal is planned to increase by 7 percent from 1980-1990, while use of coal from other states is planned to decrease by 29 percent. Substantial reductions in the use of Western coal from Wyoming and Colorado are planned, as well as no further use of Kentucky coal. The modest increase in the use of Illinois coal planned for 1985 and 1990 reflects construction of new plants equipped with scrubbers. Reductions in use of

Table 12.2

Past and Planned Coal Shipments from Illinois Mines to Electric Utilities

(thousands of tons)

Destination	1977[a]	1980[b]	1985[b]	1990[b]
Illinois	18,477	17,014	18,398	18,225
Indiana	3,802	9,765	9,005	9,005
Missouri	10,080	16,630	16,700	16,700
Wisconsin	3,972	3,170	1,600	1,600
Iowa	1,813	2,095	1,825	1,925
Michigan	0	1,000	0	0
Florida	1,016	3,000	5,200	5,200
Georgia	1,700	4,900	5,500	5,500
Mississippi	1,884	960	0	0
Minnesota	0	865	930	930
	42,744	59,399	59,158	59,085

(a) - University of Illinois Survey, 1979

(b) - University of Illinois Survey, 1981

Table 12.3

Past and Planned Coal Shipments from U.S. Bureau of Mines Production Regions to Illinois Electric Utilities

(thousands of tons)

Origin	1977[a]	1980[b]	1985[b]	1990[b]
Illinois	18,477	17,014	18,398	18,225
Kentucky	2,196	1,050	0	0
Indiana	455	391	337	325
Wyoming	4,406	4,824	2,682	2,682
Montana	6,762	6,558	6,558	6,558
Colorado	1,388	1,530	1,480	650
	33,684	31,367	29,455	28,440

(a) - University of Illinois Survey, 1979

(b) - University of Illinois Survey, 1981

other coal reflects shifts of generating capacity to nuclear power, as well as adjustments for the lower Btu content of Western coal.

The above findings indicate a positive trend of some extent for Illinois coal. When compared to the previous study done for 1977, 1982 and 1987, however, some discrepancies are found, especially between the previous plans for 1987 and the current plans for 1990. For example, the total planned use by virtually the same states as shown in Table 12.2 for 1987 amounts to 68 million tons of Illinois coal, whereas the planned use for 1990 is only 59 million tons. The only state which showed an increase in future plans from the former study to this study was Missouri, which showed an increase from 13.7 million tons in 1987 to 16.7 million tons for 1990. This increase is mainly attributed to a 3 million ton contract negotiated between Union Electric and Amax Coal.

Another area of discrepancy arises when comparing Table 12.3 with its counterpart in the former study. Planned coal shipments from out-of-state mines into Illinois amounted to 21.7 million tons for 1987, as compared with 10.2 million tons for 1990. Although the shipments of Illinois coal to Illinois utilities show a slight increase from 1987 to 1990, it is not enough to account for the reduction from out-of-state mines. One principal cause of this reduction, as well as the reduction noted in Table 12.2, is that utilities were much more optimistic about the future demand for electric power in 1977 than in 1980. The second important explanation for this discrepancy is found in Table 12.4. As indicated in the table, Illinois is continuing to shift toward nuclear power in the future, as it has in the past. What coal Illinois plans to use in the future will increasingly come from Illinois; however, much of Illinois' future additions to generating capacities are planned for nuclear, and not coal, powered plants.

Table 12.4

Additions to Steam-Electric Generating Capacity in Selected States, 1979-1988

Capacity in Megawats (percent of total)

State	Nuclear	Bituminous Coal	Subbituminous Coal	Oil	Total
Illinois	9,516 (85)	1,099 (10)		635 (5)	11,250
Wisconsin	900 (25)		2,680 (74)	64 (1)	3,644
Missouri	2,800 (55)	1,147 (22)		1,170 (23)	5,117
Iowa		1,150 (38)	1,901 (62)		3,051
Indiana	2,904 (30)	6,680 (68)		215 (2)	9,799
Kentucky		5,889 (91)		585 (9)	6,474
Georgia	10,405 (80)	2,580 (19)		45 (1)	13,030
Florida	847 (7)	7,383 (66)		3,022 (27)	11,252
Total	27,372 (43)	25,928 (40)	4,581 (8)	5,736 (9)	63,617 (100)

Source: U. S. Department of Energy, Additions to Generation Capacity 1979-1988 for the Contiguous United States, Economic Regulatory Administration, Washington, D. C., 1979.

In comparing the total planned additions for the group of states shown in Table 12.4 with similar information for 1978-1987, one sees a substantial increase in additions to nuclear power and an even larger decrease in coal-fired plants. Because these plans may be subject to change, it would be highly speculative to draw sweeping conclusions from differences reported over a one-year period. Nevertheless, this aspect of the future plans of utilities should be carefully monitored in the future.

12.2 Mode of Coal Transportation in 1980

In addition to the origin and destination of coal shipments in 1980, information was obtained on mode of shipment. A summary of these data are shown in Table 12.5. Shipments within Illinois occurred over distances as short as 25 to 100 miles, as well as longer distances. On a total tons basis, trucks transported about the same amount as rail. As the length of haul increased in shipments to and from out-of-state locations, rail transport became more dominant. The utilization of unit trains in out-of-state shipments was most prevalent in the survey response. Unit trains were also common in movements within Illinois, especially by the utility companies with larger, contract purchases.

A good example of this type of shipment is found in the arrangement that Central Illinois Public Service Company has made with the ICG Railroad to transport about 1.25 million tons of coal per year from Dykersburg, Illinois to its plant at Newton, Illinois. Other utility companies within Illinois that have unit train arrangements are Electric Energy with the Missouri-Pacific Railroad and Commonwealth Edison.

Table 12.5

Transportation Mode of Coal Shipments, 1980

(percent of total tons)

Mode or Mode Combination	Illinois To Illinois	Illinois to Out of State	Out of State To Illinois
Truck	38	0	6
Rail	38	51	47
Barge	4	9	0
Conveyor	4	0	0
Rail/Barge[(a)]	12	40[(b)]	47[(c)]
Truck/Rail	4	0	0
Total Tons	17,014	42,385	14,353

(a) Some rail/barge shipments may utilize trucks as well, but normally in only a short-haul loading capacity.

(b) Rail was utilized within Illinois; barge was utilized to move to other states.

(c) Rail was used to move to Illinois; barge was used to move within the state.

Source: University of Illinois Survey, 1981

A more detailed pattern of all coal flows may be found by summarizing Federal Energy Information Administration data for 1980 as was done in the former study for 1976. Tables 12.6 and 12.7 show data relating to shipments of coal into and out of Illinois, use and mode used.

Table 12.6 shows 1980 flows of Illinois coal within Illinois, to surrounding states and to the Southeastern U.S. According to the Federal data, 62 million tons of coal were mined in Illinois of which 53 million tons were consumed by electric utilities. In contrast, Table 12.2 shows 59 million tons of Illinois coal consumed by utilities. The difference of 6 million tons evidently results from differences in reporting in the two surveys. Some of the discrepancies may occur because the Federal data are reported by mine, whereas the University survey is by electric utility. According to the Federal data, Illinois, Missouri and Indiana utilities consumed 75 percent of utility coal mined in Illinois; the comparable result for Table 12.2 is 73 percent.

Rail was used for 59 percent of all utility coal shipments: inland waterways moved 32 percent, the trucking industry, 5 percent, conveyors, 4 percent, and the Great Lakes, less than 1 percent. It is important to note that these figures represent the predominant mode of transportation; most coal movements involve some minor rail and/or truck movements as well. It should also be pointed out that these figures are in tons not ton-miles, so the modal share is not indicative of the actual role played by each mode.

Table 12.7 shows total shipments of utility coal to Illinois users in 1980 to be 36 million tons, of which 51 percent was mined in the state. Total utility coal consumed in Illinois is about 5 million tons higher in the Federal survey than in the University survey. Western coal was responsible for an additional 44 percent of Illinois coal consumption. The remaining

Table 12.6

Shipments of Illinois-Produced Coal in 1980
by Destination, Use and Transportation Mode

Destination
(thousands of tons)

Mode & Use	Illinois	Missouri	Indiana	Midwest[a]	Southeast[b]	Total
Rail						
Utility	9,658	9,911	7,591	3,558	432	31,150
Other	998	626	2,784	1,007	8	5,423
Util/Tot %	91%	94%	73%	78%	98%	85
River[c]						
Utility	4,730	2,728	-	1,773	7,465	16,696
Other	192	26	-	291	447	956
Util/Tot %	96%	99%	-	86%	94%	95
Truck						
Utility	2,397	11	25	136	0	2,569
Other	1,683	646	69	191	3	2,592
Util/Tot %	59%	2%	27%	42%	0%	50
Conveyor-Util	1,915	-	-	-	-	1,915
Great Lakes						
Utility	-	-	-	295	-	295
Other	-	-	-	179	-	179
Util/Tot %	-	-	-	62%	-	62
All Modes						
Utility	18,700	12,650	7,616	5,762	7,897	52,625
Other	2,874	1,298	2,853	1,668	458	9,151
Util/Tot %	87%	91%	73%	78%	95%	8[illegible]

(a) - Wisconsin, Iowa, Minnesota, Michigan, Ohio
(b) - Georgia, Florida, Kentucky, Tennessee, Alabama, Mississippi, Louisiana
(c) - Usually involves rail or truck shipment

Source: U. S. Department of Energy, Bituminous Coal and Lignite Distribution, Energy Information Administration, Washington, D. C., 1980.

Table 12.7

Shipments of Coal to Illinois in 1980
by Origin, Use and Transportation Mode

Mode & Use	Illinois	Eastern[a]	Kentucky Indiana	Wyoming	Other[b] Western	Total
			Origin (thousands of tons)			
Rail Only						
Utility	9,658	-	93	10,366	5,551	25,668
Other	998	409	1,479	-	-	2,886
Util/Tot %	91%	-	6%	100%	100%	90%
River[c]						
Utility	4,730	-	1,360	-	-	6,090
Other	192	100	132	-	-	424
Util/Tot %	96%	-	91%	-	-	93%
Truck						
Utility	2,397	-	401	-	-	2,798
Other	1,683	-	232	-	-	1,915
Util/Tot %	59%	-	63%	-	-	59%
Conveyor-Util	1,915	-	-	-	-	1,915
Great Lakes						
Utility	-	-	10	-	-	10
Other	-	203	-	-	-	203
Util/Tot %	-	-	100%	-	-	5%
All Modes						
Utility	18,700	-	1,864	10,366	5,551	36,481
Other	2,874	712	1,843	-	-	5,429
Util/Tot %	87%	-	50%	100%	100%	87%

(a) - Virginia, West Virginia, Pennsylvania, Ohio
(b) - Montana, Colorado, Washington, Oregon
(c) - Usually involves rail shipments from mine to river

Source: U. S. Department of Energy, Bituminous Coal and Lignite Distribution, Energy Information Administration, Washington, D. C., 1980.

amounts of coal consumed in Illinois came from Indiana and Kentucky. Rail transportation was responsible for transporting 52 percent of the utility coal used in Illinois, and all of the utility coal moved from the West.

12.3 Conclusions

Comparison of the results from the surveys conducted in 1979, 1980 and 1981 indicate substantial shifts in the amount and source of coal consumed by electric utilities. The data on planned shipments, therefore, appear to be somewhat less useful than initially believed. These shifts, of course, reflect the substantial uncertainties faced by the electric utility industry in the source and type of fuel being used for electric power generation. Further efforts to collect data of this type, therefore, would seem to be useful mainly as a means of monitoring transportation conditions, rather than a method of identifying future transportation requirements.

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his report expands on work initiated by a previous Department publication, Implications of Expanding Coal Production for Illinois Transportation Systems". art one of this studyexamines and evaluates prospects and determinants of the xport market for Illinois coal and identifies trade barriers and the necessary ransportation investments. Part two of the study identifies and assesses some of he potential consequences that a coal slurry pipeline to Georgia, Florida and labama might generate for Illinois. Part three is an analysis of past and planned sage of coal by electric utilities with respect to Illinois.

he report provides information and analysis that will hopefully lead to an bjective, reasoned policy debate concerning how these issues affect the State f Illinois.

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